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The principal objective of this symposium was to identify the environmental benefits and threats of alternative energy conservation systems and to compare the environmental impacts of energy conservation strategies. It was also an objective of the symposium to anticipate and publicize environmental impacts so as to: facilitate proper consideration of these impacts in the assignment of funding priorities for energy conservation programs under the national energy research and development program; and begin work in a timely manner to solve future environmental problems.

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# SYMPOSIUM ON
# ENVIRONMENT AND ENERGY CONSERVATION
# (NOVEMBER 1975, DENVER, COLORADO)

Franklin A. Ayer (Compiler)
Research Triangle Institute
P.O. Box 12194
Research Triangle Park, NC 27709

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U.S. ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION
Office of the Assistant Administrator for Conservation
Washington, DC 20545

This report has been reviewed by the Environmental Protection Agency (EPA) and the Energy Research and Development Administration (ERDA) and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of EPA or ERDA, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

# FOREWORD

The proceedings for the symposium on "Environment and Energy Conservation" is the final report submitted to the Industrial Environmental Research Laboratory for the Environmental Protection Agency, Research Triangle Park, North Carolina (Contract No. 68-02-1325), and the Energy Research and Development Administration, Office of the Assistant Administrator for Conservation, Washington, D.C. (Purchase Order No. WA-76-3777). The symposium was held at the Denver Marriott Hotel, Denver, Colorado, on 3-6 November 1975.

The principle objective of this symposium was to identify the environmental benefits and threats of alternative energy conservation systems and to compare the environmental impacts of energy conservation strategies. It was also the objective of the symposium to anticipate and publicize environmental impacts so as to: (1) facilitate proper consideration of these impacts in the assignment of funding priorities for energy conservation programs under the national energy R&D program and (2) begin work in a timely manner to solve future environmental problems.

Mr. Walter B. Steen, Chemical Engineer, Energy Assessment and Control Division, Industrial Environmental Research Laboratory, Environmental Protection Agency, Research Triangle Park, North Carolina, and Mr. Kelly D. DeVine, Environment and Safety Specialist, Office of the Assistant Administrator for Conservation, Energy Research and Development Administration, Washington, D.C., were Co-General Chairmen of the symposium.

Mr. Franklin A. Ayer, Manager, Technology and Resource Management Department, Center for Technology Applications, Research Triangle Institute, Research Triangle Park, North Carolina, was the Symposium Coordinator and Compiler of the proceedings.

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3 November 1975

## INTRODUCTION AND OPENING REMARKS

P. P. Turner*

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*Chief, Advanced Process Branch, Energy Assessment and Control Division, Industrial Environmental Research Laboratory, Environmental Protection Agency, Research Triangle Park, North Carolina

# INTRODUCTION AND OPENING REMARKS

P. P. Turner[1]

Good morning, I am Pic Turner of EPA and I am delighted that you can be here. Our symposium on "Environment and Energy Conservation" is sponsored jointly by EPA and ERDA.

Dr. John K. Burchard, Director of EPA Industrial Environmental Research Laboratory of Research Triangle Park, North Carolina, was originally scheduled to make the welcoming address. Dr. Wilson Talley of EPA headquarters had last minute demands on John's time and it is with deep regret that he cannot be here. Speaking for the Environmental Protection Agency, I extend a hearty welcome to the Energy Research and Development Administration, which joins us as cosponsors of this symposium on energy conservation and the environment. Since the two issues—energy conservation and the environment—are inseparable, this cosponsorship is quite appropriate in our search for an environmentally clean solution to our country's energy problems. Everyone is aware of these problems. They range from where they are most evident, in the not-so-broad American pocketbook, to where they are not quite so evident, but certainly more important, the not-so-happy American body.

The overall program represents an international balance of expertise from industrial, academic, and government communities. The purposes of this symposium are: to identify the environmental benefits and threats of alternative energy conservation systems; to examine our energy conservation strategies and their implications; to look at several nontechnical methods of conserving energy; to consider the implications of retrofitting present-day energy systems, central power stations, and residential and commercial energy systems; and to examine the environmental impact of certain industrial processes.

As a spokesman for both the EPA and ERDA, I extend a hearty welcome to the speakers scheduled for this timely and important meeting. Each speaker is fully qualified in his or her own particular facet of this complex arena of research, development, demonstration, legislation, and enforcement activities. And speaking both for the cosponsors and for the speakers, I extend the heartiest welcome to you who are usually referred to at these meetings as attendees. Your presence is proof of the interest, time, energy, and effort being extended by many talented and productive people to help meet the energy and environmental conservation challenge. Once again, welcome to Denver.

---

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# ENERGY CONSERVATION POLICY AND OVERVIEW

Dennis W. Bakke[1]

## *Abstract*

*Conservation is the cost-effective substitution of capital, time, or labor for energy consumption. Viewed from this perspective, energy conservation becomes an equal partner with efforts to increase energy supplies. Quite literally, a barrel of oil saved is equal to a barrel of oil produced.*

*The overall potential for energy conservation, using existing technology, is enormous. Because conservation is in the economic self-interest of all energy users, a large portion of the potential will be achieved without further Federal intervention. Nevertheless, the Federal Energy Administration (FEA) estimates that additional savings of about 7.5 million barrels per day are achievable by 1985. Without the enactment of pending legislation and the expansion of existing programs, however, only about half of the potential savings in 1985 is likely to be realized.*

*By comparing the cost of such conservation measures as installing insulation and storm windows or manufacturing more fuel-efficient automobiles to the cost of increasing energy supplies, it is clear that conservation is our cheapest future "source" of energy.*

*There have been numerous proposals to accelerate the Federal energy conservation effort, which has up to now been constrained by limited funding and authority. But, unfortunately, the Administration and Congress remain deadlocked on many key issues. Hopefully, these issues can soon be resolved, enabling us to stop talking about the problem and begin concentrating on solving it.*

It is now generally accepted that energy conservation should be a major objective of any national energy policy. But there is still much disagreement on what specific steps should be taken and, I believe, much misunderstanding of the real meaning of energy conservation.

The Congress and the Administration remain deadlocked over many key issues, and the ensuing confusion has encouraged public indifference. Nevertheless, I feel there is still some hope that the major issues can soon be resolved, permitting us to stop talking about the problem and begin concentrating on solving it.

Before discussing my own views on energy conservation and summarizing the status of Federal programs and legislation, I would like to list the basic components of our national dilemma on which there is general agreement.

1. Domestic reserves of oil and natural gas are limited—and declining at an alarming rate;
2. A heavy reliance on imported petroleum poses a serious threat to both our economy and national security;
3. Expanding domestic supplies of energy, whether they be from conventional or exotic sources, will take many years, and these new supplies are likely to be increasingly costly;
4. Energy supply, conversion, and use often pose serious threats to environmental quality.

Some time ago, largely because of a growing recognition that these conflicting problems could not be easily resolved, many persons began seriously to examine the potential for reducing energy demand. It could not be disputed that the rapid growth in the demand for energy during the past two decades was largely responsible for our heavy reliance on imported oil. Furthermore, the profligate waste of energy seemed to be self-evident. But was it? Critics of conservation asserted that economic growth was dependent upon increasing energy consumption, and, at first glance, this conclusion appeared to be supported by similarities between the growth in GNP and energy demand and by a simple comparison of the energy use per capita of the United States and that of any underdeveloped country. In addition, it was apparent that turning off lights, eliminating electric toothbrushes, and driving slower certainly would not solve the problem.

Fortunately, these criticisms did not deter the advocates of conservation. The list of opportunities for saving energy, together with our perception of the overall potential, rapidly expanded. It soon became evident that conservation did not necessarily pose a threat to economic growth. On the contrary, saving energy could lead to higher productivity without any loss in comfort, services, or goods. In fact, because energy costs are likely to continue to rise in the future (Fig. 1), it is essential that we use energy more efficiently if we are to maintain our quality of life and continue economic growth.

Out of these initial explorations, there emerged a better understanding of what "energy conservation" really meant—in both economic and social terms.

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[1] Deputy Assistant Administrator for Energy Conservation and Environment, Federal Energy Administration, Washington, D.C.

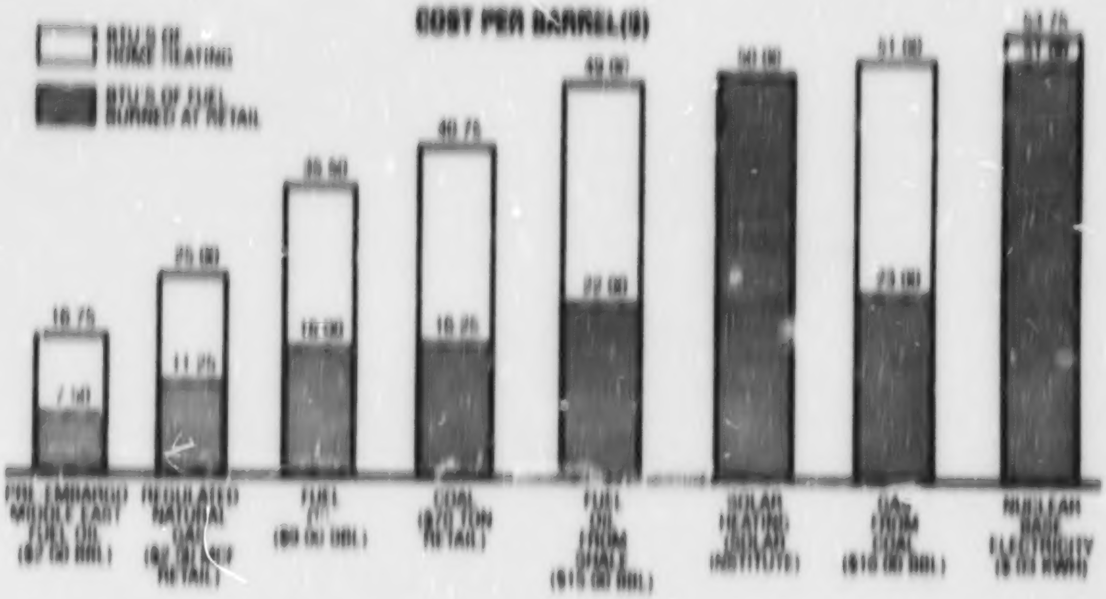

Figure 1. Rising costs of all energy sources pose a threat to the continued economic welfare of this and succeeding generations.

The term "conservation" by itself leaves considerable room for interpretation. The following categories encompass those actions which we at the Federal Energy Administration have come to accept as "energy conservation":

1. *Elimination of wasted energy*: such as extinguishing lights in unoccupied buildings at night or removing excessive bulbs in existing commercial lighting fixtures.
2. *Cost effective substitutions of human time or effort for energy use*: such as improving maintenance of energy-consuming devices, using carpools or mass transit instead of a private auto for commuting, or consolidating shipments and personal travel.
3. *Cost effective substitutions of capital investment for energy use*: such as increasing the use of insulation in buildings, investing in heat pumps instead of electrical resistance heating, or installing equipment to capture the waste heat from boilers for a useful purpose.
4. *Substitutions of alternative lower energy activities for higher energy activities which have a similar effect*: such as using telecommunications in place of long-distance travel or dressing differently to permit thermostats to be raised in the summer and lowered somewhat in the winter.

This definition does not assume that energy conservation requires any dramatic changes in the basic preferences of individuals. But it does suggest that some changes in attitudes or lifestyles will occur as a greater awareness of energy and its costs emerge. As may be seen, each of the categories represents, at least in a broad sense, a way to use energy more efficiently. Each individual makes choices regarding energy use conservation measures by weighing the importance of many different factors, including energy costs, time value, comfort, convenience, and force of habit. The cost of energy, long disregarded by most consumers and businesses, has recently become a key factor guiding these individual choices.

It is important to distinguish between the type of efforts that clearly fall into one of the categories mentioned above and those steps that might be required in the event of an emergency shortage of energy. A host of mandatory curtailments, including gasoline rationing, curbing exports, and Sunday closing of gasoline stations could be instituted to cope with serious disruptions of energy supplies. But such immediate emergency measures are viewed as distinctly different from the longer-term measures, which I believe truly constitute the "conservation" of energy. It is important not to lose this distinction, because the concerns, priorities, and the governmental roles shift dramatically.

Viewed from this perspective—that is, that conservation means improved energy efficiency and not simply reduced consumption—energy conservation becomes an equal partner with efforts to increase supplies. Quite literally, a barrel of oil saved through the adoption of cost-effective energy conservation measures is equal to a barrel of oil produced through an expansion of domestic production. For example, if a homeowner installs insulation, he will save perhaps 6 to 10 barrels of oil during the winter months. The oil saved represents a reduction in total U.S. energy use, and as a result, our dependence on imported petroleum is reduced.

This type of analysis can be used to determine the "cost per barrel saved" of conservation actions. For example, ceiling insulation can be installed in the average home for less than $300. This amount of insulation would save, on the average, 40 million Btu's of fuel annually, which is equivalent to about seven barrels of oil. Assuming that the insulation has a life expectancy of at least 20 years and that the cost of money is 10 percent, the equivalent of 60 barrels of oil would be saved. By dividing $300 by 60 barrels, we conclude that $5 worth of insulation is needed to save one barrel of oil. This figure of $5 is less than virtually every other form of energy available to the homeowner. For example, at current prices, fuel oil costs over $16 per barrel. Solar heating and electricity from nuclear power plants would also be about four times more expensive than saving fuel by installing insulation.

Similar calculations have been performed for storm windows, which cost about $9 per barrel of oil saved, and improved auto efficiency, which costs about $2.50 per barrel saved, or 6 cents per gallon. And just to show we are honest and that not all conservation options are cheap, we estimate that installing Washington's urban rapid transit system to be the equivalent of buying oil at $287 a barrel (fig. 2). Of course, this same approach can be applied to numerous other conservation measures in industry, transportation, utilities, and buildings. Without going into these measures in detail, let it suffice to say that most energy conservation measures turn out to be far cheaper than the available supply alternatives. This conclusion has relevance for individuals as well as for policymakers.

As fuel becomes more expensive, substitutes for fuel

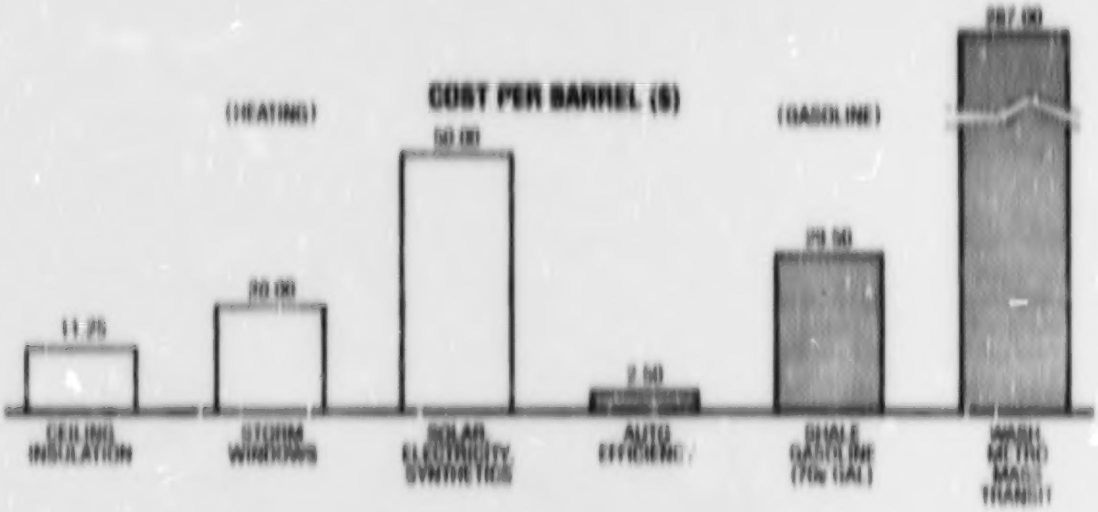

Figure 2. Since unconstrained demand for energy is greater than "business as usual" supplies:

- The market will seek supply/demand equilibrium by choosing the most cost-effective options from among *both* supply and demand opportunities;
- One way to measure cost effectiveness is cost per barrel (saved or produced).

become more cost-effective. It now pays to spend the money to make cars more efficient, to insulate buildings, to adjust thermostat settings at night, to schedule planes so they are not half empty, to improve railroad freight handling, and to modernize our factories to improve their use of energy.

By defining energy conservation measures as cost-effective substitutes for energy consumption, we can begin to assess the ultimate potential for energy savings. It is clear that as a Nation we tolerate huge amounts of energy waste. Sweden and Germany, two countries with per capita incomes approximating our own, consume only half as much energy per capita. Certainly part of the difference can be accounted for by the larger homes and greater use of transportation in the United States. But the major reason is that Germany and Sweden have responded to many years of high energy prices by improving the efficiency of energy use. For example, average new car fuel economy in Germany is 21 mpg versus 14 mpg in the United States. Furthermore, the manufacturing of paper requires only 37 percent and chemicals require only 57 percent of the energy used to produce the same amount of these products in the U.S.

We should not necessarily attempt to duplicate European energy use patterns, but they are indicative of the gross potential for energy savings. FEA estimates, for example, that by applying existing technology we could *eventually* save more than 50 percent of the energy consumed in the United States (fig. 3). To fully achieve even these savings, however, will require the replacement of much of our existing capital stock with more energy-efficient equipment, vehicles, and buildings. Because we cannot afford simply to scrap existing buildings and industries, even though they may be grossly inefficient, improvements in energy efficiency will have to coincide, at least partially, with the gradual replacement of existing facilities and equipment. Nonetheless, substantial savings can be achieved in the short term through the modification of existing facilities and practices.

Improving the energy efficiency of both new and existing buildings, vehicles, and equipment is now justified by cost savings alone, especially when compared with the cost of increasing energy supplies. It is abundantly clear that conservation is our cheapest source of energy. Because energy conservation is in the economic self-interest of individuals and businesses, we expect that most of the potential savings will be achieved without further government intervention. These "price-induced" savings are depicted by the middle line on figure 3, labeled "Business As Usual." But today's higher energy prices will not achieve the full potential for conservation alone. We believe there is the

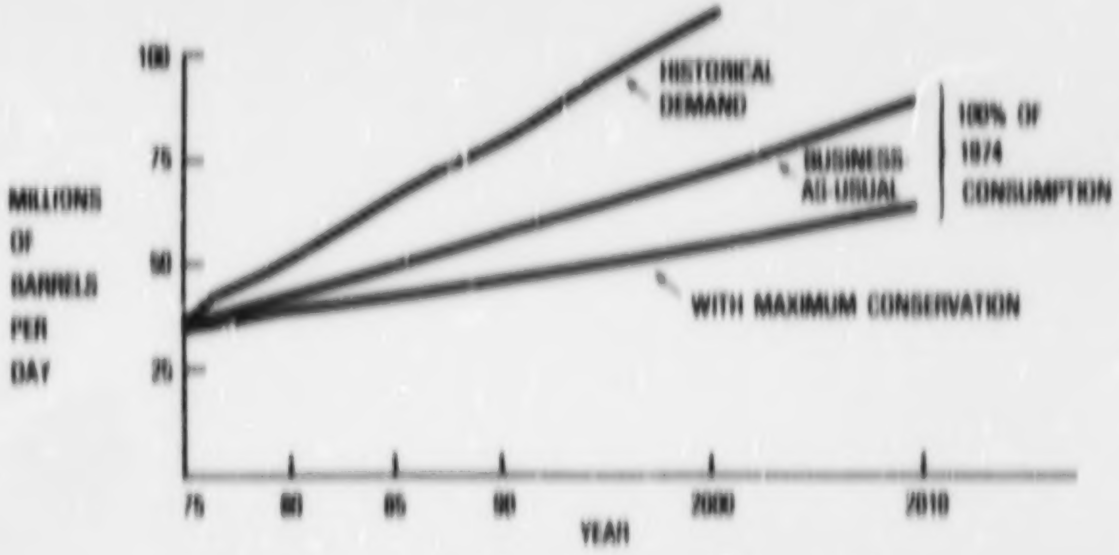

Figure 3. The potential: A composite demand picture shows that cost effective conservation has the *theoretical potential* to reduce demand by 16 percent in 1985 and 29 percent in 2010.

additional potential, for example, to save about 5 million barrels per day of oil equivalent by 1980, 7.5 million barrels per day by 1985, and more than 15 million barrels per day by the year 2010.

Most of this potential can be realized by energy conservation measures, which fall into one of six general categories:

*In transportation:*

1. Improving the fuel economy of motor vehicles.
2. Reducing vehicles miles traveled.

*In residential and commercial buildings:*

3. Designing and building more efficient new structures and appliances.
4. Improving the energy efficiency of existing buildings and homes.

*In utilities:*

5. Reducing the amount of scarce fuel required to generate each kWh of electricity.

If individuals and businesses were totally committed to conserving energy and aware of the opportunities to save, we would not have nearly as serious a problem as we do today. But, for a variety of reasons, the response to the calls for energy conservation has not been as strong nor as enduring as we might have hoped. Certainly the dramatic increases in the price of fuel and the increased awareness of the need for conservation have resulted in some significant savings. Energy demand so far this year has been somewhat less than 1973 levels. Considering that energy demand grew at about 4.3 percent annually from 1964 to 1973, no growth in demand for nearly 2 years is certainly an important accomplishment. Although the recession accounts for a significant portion of this reduction, FEA believes that conservation has reduced petroleum consumption on the order of 5 percent from what it would have been otherwise. This is the equivalent of at least 1 million barrels of oil per day. The slackening of the rate of energy demand growth is a significant achievement, but, as figure 3 indicates, there remain opportunities for substantially greater savings.

Because there is an overriding national interest in reducing our dependence on imported petroleum, the Federal Government has actively sought ways to increase the conservation of energy. Unfortunately, the Federal effort, up to now, has been constrained by limited authority and inadequate funding. Current Federal activity, with the exception of the 55 mph speed limit, falls into four general areas:

1. *Information transfer.* This includes the distribution of pamphlets and other materials on conserving energy, public service advertising, and several programs that involve direct contacts with building managers, industry groups, and individuals.
2. *Goal setting.* This includes Federal programs directed at improving automobile fuel economy (40 percent by 1980), appliance efficiency (20 percent by 1980), and industrial energy efficiency (10 to 15 percent by 1980), as well as programs in the development stage, which will involve utilities and individual States.
3. *Research and development.* This includes all efforts directed at the development of more energy-efficient technologies. With the establishment of the Energy Research and Development Administration, Federal energy conservation R&D efforts have expanded and become more cohesive.
4. *Import tariffs.* Although the President has continually urged Congress to adopt measures that would replace the current $2 per barrel tariff and has pledged to remove the tariff if the price of "old oil" were completely decontrolled, it remains the only measure now in effect that encourages conservation by artificially raising the price of energy.

FEA estimates that the combination of these existing programs (excepting the oil import tariff) will result in savings of approximately 2.5 million barrels per day by 1980 and 3 million barrels per day by 1985. This means that, without further Federal action, only half of the economically justified potential for energy savings will be achieved during these years and even less in the future.

If, as I contend, energy conservation is in the economic self-interest of individuals and businesses, why is only a portion of the overall savings potential being achieved? Although we still do not have all the answers, we know that many factors exist which prevent the marketplace from providing the appropriate signals or which prevent individuals from taking totally rational actions with regard to energy use.

First, Federal regulations have kept oil and gas prices below world market prices. This factor has continued to hamper our response to the radical changes brought on by the 1973 oil embargo and the dramatic increases in the price of oil on the world market. Secondly, energy-efficient homes, buildings, and products are generally more expensive than less efficient homes, buildings, or products. This is because more efficient products require more careful engineering and design, material inputs with better (more expensive) thermal characteristics, or other special energy-conserving features. Because of a lack of information and longstanding consumer habits, purchases are made on the basis of initial cost rather than lifecycle costs—which include the cost of the energy needs of the product. This market factor encourages the design, construction, and sale of relatively inefficient products.

Another general category of market imperfection is the lack of information available to individuals, firms, and units of government regarding opportunities for conservation. This ranges from a lack of information on the savings achievable through adjustments in thermostats to an inadequate technical understanding of heat-recovery systems.

A final but important factor that prevents a quick response to rising energy prices is that a large portion of the American economy no longer responds rapidly or completely to traditional market forces. The largest 1,000 firms in the United States produce approximately half of the total goods and services, with the other 12 million firms (and farms) producing the remaining half. These 1,000 firms have relatively greater control over the prices they charge than do the rest of the firms in the economy, and they, therefore, have greater ability to pass on the effect of increasing energy costs. The relatively large market shares and advertising budgets of these 1,000 firms help them maintain demand for their products while simultaneously increasing the prices of their products in response to the higher energy costs. This factor reduces the incentive of those large firms to respond to the market signals of rising energy prices through energy conservation. In a similar manner, the Nation's utilities can also pass on their cost increases to the consumer, making this category of firms slow to respond to new market conditions.

Federal energy conservation efforts are justified to the extent that they alleviate market imperfections in order to achieve a more cost-effective allocation of scarce national and world energy resources. Justifiable Federal energy conservation efforts are not attempts to replace the market mechanism, but instead to reinforce the market and help it operate in a more nearly perfect manner.

What more can the Federal Government do to achieve conservation? I believe that much can be done, both through the enactment of pending legislation and through the expansion of existing voluntary programs.

In January 1975, the President proposed a wide-ranging program both to increase domestic supplies of energy and to reduce consumption. The program included excise taxes on both oil and natural gas, price decontrol coupled with an excess profits tax, and provisions for the return of these increased Federal revenues to individuals and businesses, as well as to State and local governments. It was recognized that increasing energy prices posed some threat to the economy by adding to the general rate of inflation, and the rebate provisions were proposed to help counteract these impacts. Our estimates of the resulting energy savings were based on relatively conservative assessments of the demand elasticity for petroleum. We assumed that every 10-percent increase in price would result in about a 1.9-percent decrease in demand within 2 years. Nevertheless, in view of the available alternatives, the price mechanism seemed to be the most effective and least disruptive means of achieving savings in the short run.

Unfortunately, the issues surrounding the decontrol of domestic oil prices, gasoline taxes, crude oil excise taxes, import quotas, and the import tariffs have dominated the media and obscured the host of other conservation proposals and programs initiated by both the President and the Congress.

For example, the President has proposed legislation to establish mandatory energy conservation standards for new residential and commercial buildings. (Note: This mandatory conservation proposal was recently made voluntary by the House.) He also has proposed tax credits for individuals who install insulation or make other energy-conserving modifications to their homes; mandatory appliance and motor vehicle labeling; and legislation to authorize and fund a program to winterize the homes of low-income persons. As mentioned earlier, the Administration has established voluntary programs to improve automobile fuel economy and appliance efficiency. In these two instances, the President has pledged to seek mandatory legislation if progress toward the established goals is insufficient. FEA, in cooperation with other Federal agencies, has also established programs to encourage greater energy conservation in industry, buildings, and electric utilities, and has just recently instituted a program to improve truck and bus fuel economy.

Although Congress has yet to enact any energy conservation legislation, it has considered many proposals to mandate some of the existing voluntary conservation programs. For example, both the House and the Senate have passed legislation mandating increased automobile fuel economy. The House has also passed a bill that would authorize the establishment of mandatory appliance efficiency standards. On the other hand, the House rejected a proposal to require major industries to submit energy conservation plans and report energy use data to the Federal Energy Administration.

It now appears that the Congress will eventually enact legislation mandating automobile fuel economy improvements and energy efficiency labeling for appliances and autos; directing the development (and perhaps mandating the adoption) of minimum performance standards for new buildings and guidelines for appliance efficiency, and establishing tax incentives for the purchase of insulation, storm windows and doors, solar heating and cooling equipment, and perhaps a wide range of other "energy-conserving" products. Unfortunately, only the tax credits for insulation and storm windows and doors are likely to have a significant impact on energy demand in the near future, and even the savings resulting from such incentives will only scratch the surface of the overall potential.

Thus, we are left with only two alternatives to stimulate immediate conservation: (1) increasing energy prices through rapid decontrol or excise taxes on domestic oil and natural gas, and/or (2) expanded Federal efforts to inform and motivate individuals and businesses.

It now seems unlikely that Congress will enact legislation that would permit a substantial rise in energy prices within the next 2 years. As a result, FEA has begun to examine seriously the possibility of greatly expanding many of our existing voluntary programs.

In the transportation sector, reducing energy consumption by automobiles has long been recognized as the major short-term opportunity for savings. The increasing demand for fuel efficient cars, together with the Administration's fuel economy improvement program and the threat of Congressionally mandated standards, virtually assure that new car fuel economy will increase as rapidly as is economically feasible. Thus, the major remaining opportunity for energy conservation in this sector is by reducing the number of vehicle miles traveled. To help achieve this end, FEA has embarked on a major new program to encourage the widespread use of vanpools to replace commuting by automobile. Vanpooling holds many advantages for both the employers, who purchase the vans and initiate the program, and the employees. Although vanpooling cannot replace efforts to increase carpooling and the use of public transit, we do believe it could make an important contribution.

In the buildings sector, energy use falls into basically two categories: (1) space heating and cooling, and (2) appliances. The enactment of mandatory appliance efficiency labeling and the achievement of the 20-percent efficiency improvement goal should insure that most of the potential for reducing appliance energy use is achieved. The potential for energy savings in space heating and cooling, on the other hand, is not likely to be achieved with existing programs. If legislation mandating energy conservation standards for new buildings is enacted, it would insure that at least new structures are thermally efficient. However, the overall energy savings achieved in new buildings will accumulate very slowly. Clearly, some action must be taken to conserve energy in existing homes and offices if we are to have a significant near-term impact. Enactment of tax credits for energy-conserving investments in residential and, perhaps, commercial buildings would encourage greater conservation, but our research indicates that it is not only the cost of such measures that is holding back their widespread adoption. Inadequate information on the opportunities for and benefits of energy conservation has certainly contributed substantially to the inaction. To help overcome this barrier, FEA hopes to go nationwide with a program that we call "Project Conserve" and to expand greatly our "Lighting and Thermal Operations Program."

Under Project Conserve each of the 47 million homeowners in the United States would be asked to fill out a questionnaire on the characteristics of their home, such as the type of construction, the amount of existing insulation, and the number of storm windows. The data is run through a computerized model, and the result shows the potential dollar and energy savings to be realized from five energy-conserving actions that can be taken by the homeowner. It is estimated that this program can save the equivalent of 80,000 barrels of oil per day and, at the same time, increase public awareness of energy conservation.

The Lighting and Thermal Operations Program is directed at commercial buildings. It uses guidelines developed by FEA, which were based on actual experience in both Federal and non-Federal buildings. The guidelines prescribe specific levels for both interior lighting and temperatures, and also provide general suggestions for reducing energy consumption. The program has a goal of reducing by 25 percent the amount of energy used in lighting, heating, and cooling commercial buildings. FEA regional employees have made calls on commercial building owners around the country to describe the energy and dollar savings that can be realized by adopting the guidelines and to ask for their participation. In addition, FEA is developing a program to encourage owners of existing commercial buildings to reduce consumption by at least 30 percent by 1980 through the installation of new heating and cooling systems and insulation and through other energy-conserving capital investments.

In the industrial sector the opportunities for conservation are substantial but somewhat more complex than in either buildings or transportation. FEA, together with the Department of Commerce, is currently working with 10 of the most energy intensive industries to help them establish effective energy conservation programs. Goals for improving energy efficiency have been established, and their achievement is being monitored. FEA is now examining the possibility of developing energy efficiency guidelines for industrial equipment and processes and hopes to eventually expand the program to include 90 percent of all industrial plants. Such an expansion might result in savings as high as 450,000 barrels per day.

Electric utilities account for nearly 25 percent of total U.S. energy use, and yet opportunities for improving load factors and reducing utility consumption of scarce fuels have only recently received serious attention. FEA is now sponsoring six load-management demonstration projects, which include such conservation measures as peak load pricing, ripple load controls, power pooling, and others. We are also intervening in State regulatory hearings concerning public utilities to voice Federal energy policy and to advocate the adoption of peak load pricing. This is another area where we hope to expand our efforts in the future. An expanded program might result in savings of 1.3 million barrels per day of oil in 1985.

Recently, FEA and the National Governors' Conference launched a State/Federal Energy Conservation Program. This program will establish a framework within which individual States can collect data on energy supply and use, project their own energy needs, and establish goals for energy conservation. FEA will provide information and assistance to those States interested in establishing specific conservation programs. FEA is also investigating the possibility of providing direct funding to the States to help support conservation programs.

Finally, we are convinced that we must greatly expand our public education efforts to help increase public understanding of the Nation's energy dilemma and the opportunities for energy conservation available to each individual.

With expanded Federal programs in each of these areas, and with the enactment of the conservation legislation now pending before the Congress, I am confident that we can achieve the bulk of the potential for energy savings in 1985. Figure 4 depicts the savings we anticipate from these expanded energy conservation programs. Nevertheless, FEA continues to explore other ways in which the Federal Government might help encourage greater savings. They include possible changes in Federal regulatory policies, mandating individual metering in multifamily house, establishing energy efficiency standards for selected industrial equipment, and providing financial and technical assistance to State regulatory commissions and utilities in their efforts to revamp rate structures and encourage conservation.

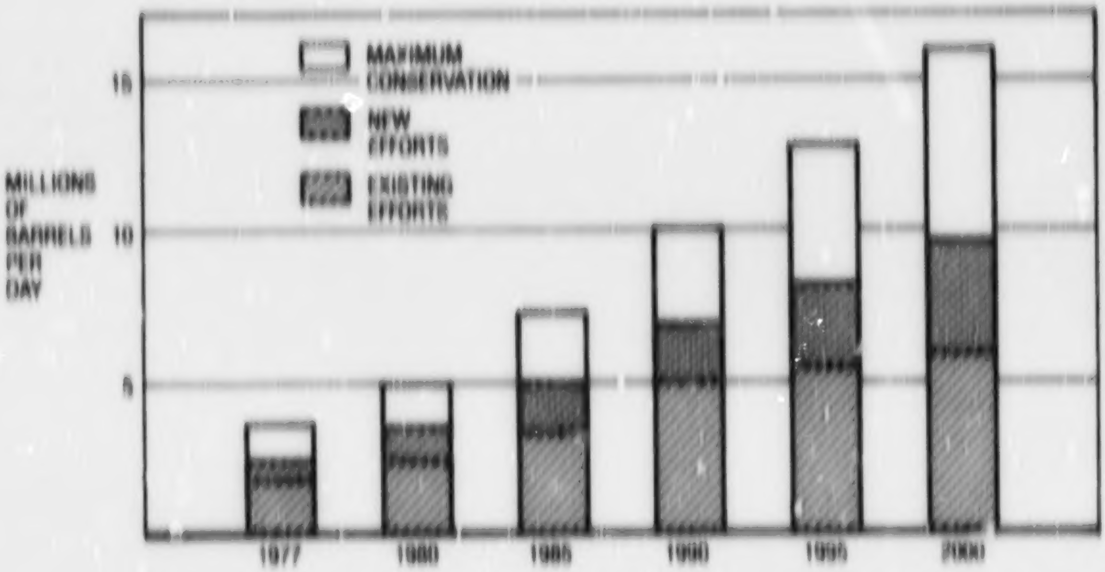

Figure 4. If we do all this, we can substantially improve the short-term results and create the consensus needed for long term results: 675,000 barrels per day by 1977, all at a total cost far less than supply options and with the American public behind the problem.

Looking beyond 1985, the opportunities for energy conservation increase. Perhaps new technologies, unforeseen today, will enable further increases in energy efficiency. Certainly, much of our current R&D program will only then begin to have an impact on energy use. Eventually we will have to direct more attention to the ways in which the Federal Government could accelerate the adoption of new energy-conserving technologies and also to the broader issues of land use, community development, and alternative transportation systems.

# THE ERDA CONSERVATION PROGRAM: THE TECHNOLOGY OF IMPROVED EFFICIENCY

James S. Kane, Ph.D.[1]

## Abstract

*This country's industry, its buildings, and its transportation systems have been constructed at a time when energy was extremely cheap. As a result, our facilities, our institutions, and our lifestyle have tended to favor the use of energy over capital and labor.*

*The uncertain availability and the not-too-distant exhaustion of low-priced energy sources require that we now examine all the ways in which our society uses energy, with the object of improving efficiencies through technological improvements. Since the use of energy pervades every aspect of our society, the task is enormous.*

*The total job to be done, however, is far more than just technical development. Conservation only occurs when and if the necessary measures are adopted by literally millions of decisionmakers. It is therefore supremely important that the entire process, from technical concepts through commercialization, be free of impediments, whether they be technical, institutional, legal, or economic.*

*The ERDA program will examine efficiency improvements in buildings—both commercial and residential, in industry, in the transportation sector, and in our electrical energy systems. In all the work, the goal is to accelerate the introduction of energy-saving technology and practices.*

*More efficient use of energy should be viewed as an alternative to increased energy production. If the economic considerations of production versus conservation are equal, the choice should favor conservation because of its more benign environmental and sociological impacts.*

When ERDA was formed last January, it marked the first time that a government agency had been given the responsibility for a comprehensive R&D program on the technical aspects of energy conservation. In the time since then, we've learned a lot about this new business—including an appreciation of how much there is still to learn. Many of the subsequent speakers at this meeting are conservation veterans, meaning they have been at it for more than a year, and I am sure much of what I will say will not be news to them. But, they will have to tolerate my talk today, because, as is true for so many converts, I cannot resist preaching the faith.

Let me start by distinguishing between two aspects of conservation that are often confused: curtailment and efficiency improvement. The former always implies a reduction in the benefits, or at least the perceived benefits to the consumer. Curtailment can be either voluntary, e.g., reduction in thermostat settings or mileage driven, or involuntary, e.g., reduced voltage, gas rationing, and speed limits. Curtailment procedures can be invoked almost instantly, which is good, but their effects, both wanted and unwanted, also come instantly, which can be bad. I am not going to spend any more time on curtailment, other than to say it will undoubtedly be necessary in the coming years, and that we should be extremely selective in the topics we choose. Incidentally, my favorite example of ideal curtailment is to turn out most of the billboard lights in Las Vegas!

The kind of conservation that ERDA is concerned with is increased efficiency, usually through technical improvements. It has been aptly observed that our country, as it exists today, is a monument to cheap energy. It has nearly always been economically advantageous to waste energy and conserve capital or labor. Now we are faced with reversing this situation, with all the difficulties that usually go along with major cultural changes. The transition will involve much more than technical developments.

How, then, do we go about identifying, developing, and bringing into being the technology of improved efficiency? In other words, how do we actually accomplish an increase in the efficiency with which the country uses energy?

Perhaps at this time I should observe that the "we" I have just used so grandly does not mean ERDA, far from it, the job will involve us all. This country has only a short time to mend its ways, and the job that must be done will deeply involve all aspects of our society. All we in ERDA can hope to do is assist in the process. Even this helping job, however, is an enormous undertaking.

What, then, do we foresee that we, as a Nation, must do? I certainly cannot claim to know all the answers to this question but, until we get smarter, I suggest the following six-step process as a testing procedure:

1. First, we must identify the ways and processes by which the country wastes energy. Much of this work

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has already been done, but it is amazing how we continue to find new wasteful habits.

2. Second, we must ask the question: Is the waste due to foolishness, indulgence, or poor technology?

3. Third, what would be the impediments to the introduction of improved technology? If capability currently exists, why is it not being used? Why have the improvements not come about from market forces?

4. What would be the impact of widespread introduction of the energy-saving technology? What are the time scales and the size of the benefits? What are the direct impacts? What are the impacts that cannot be expressed in economic terms—sociological, environmental, etc.?

5. Fifth, how can the barriers that prevent or impede using the new technology be overcome? How can we accelerate the process? What changes—legal, regulatory, institutional—should be made?

6. Finally, with the technology available, and the barriers and the means of overcoming them identified, how can we most rapidly move the technology into commercial and public use?

As you can se[illegible] business of conservation through improved tech[illegible]olves far more than just the technology itself. Th[illegible]roblem can only be dealt with holistically; if one link in the chain is ignored, the end results will not be achieved.

Now that I have outlined the approach, let me give you a very brief description of the program that we are now developing in **ERDA**. Later in this symposium, other **ERDA** speakers will describe their individual research areas in greater detail.

### *Buildings*

The building sector in many ways is the most difficult of all, for it involves by far the largest number of decisionmakers. In most cases, the technology is rather straightforward, but the nontechnological obstacles are many and difficult. Ultimately, each individual who has a choice involving conservation must clearly perceive a benefit in adopting conservation measures and, having decided to do so, be able to carry them through to successful conclusion.

Although I have emphasized the difficulties, the benefits of widespread conservation in buildings are also very great. The existing systems are grossly inefficient; very large savings of scarce fuels are possible. Since the savings are derived from many small developments, and many of them are retrofits to existing buildings, the time scale of obtaining results is relatively short. Most of the changes are labor intensive; jobs will be created. And finally, very large savings can result with virtually no change in lifestyle. This latter statement serves to illustrate that we have in the past been profligate in our use of energy in buildings; many of the benefits we got from excessive energy consumption were highly marginal. Very cheap fuel, such as Mideast oil or regulated natural gas, has been an addiction, and as is true for drugs, withdrawal will be painful. But it may surprise us how well we will feel without such large doses.

### *Industry*

The introduction of energy-saving technology into industry is a much different process than that in buildings. The clients are fewer in number, are economically sophisticated, and are in general keenly aware of the problems and the means to overcome them.

Our program in industry will therefore emphasize technological development less and concentrate more on means by which we can assist industry in implementing its solutions. We will do this by cooperating in demonstrations to establish technological and economic risk, on information transfer in the more fragmented industries, and on the nontechnological barriers that prevent conservation measures from being adopted. A good example of the latter is the production of electric power by industries that use large amounts of process heat. The problems in this example are neither technical nor economic; rather, they are principally those involved in sale and transport of large blocks of power between nonregulated industry and regulated utilities.

Widespread conservation in industry will ultimately lead to many process changes and will require enormous amounts of capital. The extensive dependence on natural gas in several industries will force a very high priority for change in the areas affected.

### *Transportation*

A basic aspect of economic prediction is price-demand elasticity; as the price of a commodity rises, demand should decline. Americans have reacted to the post-embargo gasoline price increases indirectly—they are not driving less, but they are buying cars with higher mileage capability. In the short term, auto manufacturers will provide more economical cars by decreasing weight, engine size, and performance. These changes involve currently available technology.

In the longer term, automobiles should be made far more efficient than they are today, by improvements in the engine and other components. There are several heat engines that promise greatly increased performance and low emissions compared with the current spark-ignited internal combustion engine. Such engines, however, are not yet available. Their successful development is a very large task, and their introduction into economic mass production is an even greater one.

Although personal automobiles are by far the largest factor in transportation energy consumption, other forms of transportation must also be considered, with an eye to improved economy and multifuel capability. Simply put, we must prepare for a future in which petroleum fuels are increasingly scarce and costly, and replacements, such as coal-derived fuels or shale products, are apt to be expensive even in terms of today's cartel prices.

The two options we foresee for highway vehicles are new, highly efficient engines capable of multifuel use, and vehicles using stored energy originally derived from coal or nuclear. Our transportation program is designed to aid in the development of this technology.

Transportation includes modes other than highway vehicles. Some areas such as pipelines do not have the capability for improvement that highway systems do, but there are significant energy saving developments possible.

### *Electrical Energy*

The other major area within conservation is electrical energy systems—chiefly the transmission, distribution, and storage of electricity. Most predictions of the future involve an increased trend toward electrification, as we utilize currently available sources, such as coal and nuclear, and learn to use new sources such as solar and fusion energy.

Our current system for transmitting and distributing electricity is about 90 percent efficient, but further improvements are possible. Higher voltage for both a.c. and d.c. is needed. Very large shipments of energy, as from power parks, would be more feasible if new developments in superconducting lines were possible.

Another aspect in which our current system is deficient is in its use factor. The "grid" has an average load that is only about 55 percent of its peak capacity; a great waste of installed capacity in a capital-intensive system. Better management of the system, including load leveling through technological (storage) and nontechnological (time-of-day pricing) would give additional capacity with a minimum of additional investment.

Until now, I have tried to give you a list of technical tasks our Nation must accomplish if we are to use energy more sensibly. For my last few minutes, I want to make a few comments on the merits of conservation that explain why conservation and environmental protection share common goals, as well as the sponsorship of this symposium.

I have often heard it said that "conservation is *only* a means of buying time," or "conservation will tide us over until we develop new, cheap forms of energy." I think it is high time we conservationists rebelled against being such stepchildren. I want to spend my first few minutes telling you why I believe conservation is not just a good way to go. It is the best way to go.

In my opinion, it is highly unlikely that we will ever again see such cheap energy as our domestic natural gas, or Mideast oil. Coal is bound to be expensive, once it is made to pay its way in terms of occupational safety and environmental responsibility. Its production as well as its use, whether via direct combustion to produce electricity or conversion to synthetic fuels, is highly capital intensive. Nuclear sources, fission and fusion, are potentially very hazardous, and suffer from being even more capital intensive than coal, especially when total fuel-cycle costs are included. Solar energy, while perhaps the least damaging to the environment, is almost sure to remain extremely, perhaps prohibitively, expensive, except as a source of low-grade heat. So the promise of future supplies of cheap and abundant energy seems dubious, to say the least.

I therefore think it highly likely that conservation is here to stay. As a society, we are only now starting to question the dogma of exponential energy growth. Yet to anyone who has given the question any thought, it is obvious that someday energy production must cease to grow. In my opinion, the most complex question facing the next generation is how to get off this curve of exponential demand for energy without catastrophe. There are advocates who claim that GNP, well-being, and energy use are all locked into an immutable relationship. I would urge them to examine more closely the coefficients in this equation, since they are the constants that measure the efficiency with which we transform energy into per capita national product, or other measures of well-being. It has been pointed out that these constants are not the same for all countries, and I also believe we can change them with an intelligent program in conservation.

Further, I think we in conservation must present our case more aggressively. To paraphrase Ben Franklin, a barrel saved may be worth more than a barrel produced. In many instances it is far more cost beneficial to invoke conservation than to produce additional fuel. And I am sure it is not necessary for me to point out to an environmentally concerned group such as this that conservation technology is gentler to the environment than energy production, which is highly capital intensive and very low in labor intensity. Almost any other sector will create more jobs per dollar invested.

I therefore maintain that conservation through improved efficiency is a subject that must have a great deal more attention that it has gotten until now. I am convinced that it will hold its own economically with increased production and, in fact, will often be more cost effective. Many conservation measures can be achieved in relatively small increments, and will thus not require large amounts of front-end capital. While not extremely rapid, the results will be felt sooner than those of production technology. The environmental consequences of increased efficiency are benign, and the social effects are favorable. Changes in lifestyles, if any, will be minimal and gradual. What other area of endeavor can make these statements?

# ENVIRONMENTAL IMPLICATIONS OF ENERGY CONSERVATION

Stephen J. Gage, Ph.D.[1]

*Abstract*

*Implications of energy conservation for protection of the environment are presented. The interrelationships among natural resources, energy supply and use, environmental quality, and economics are addressed, with special emphasis on the practical implications of the Second Law of Thermodynamics. It is concluded that reduced energy consumption, with the associated reduction in the flow of other matter, generally leads to reduced environmental damage. The limitations of classical economics in describing the impacts of resource shortages, as well as of nonquantifiable environmental damages, is discussed. The activities of the Environmental Protection Agency as part of the Federal research efforts on energy conservation are discussed.*

Denver is a wonderful place for a conference on the environment and energy conservation. The snowy Rockies, looming beyond the city, are a national symbol of an environment free of the fumes and haze we associate with urbanized, industrialized society. Yet, even though a view of the mountains is all too often obscured by a curtain of pollution, Denver has become a seat of the fight against unquestioned and questionable growth. Widespread concern in Colorado over the potentially explosive growth of energy resource exploitation in the western part of the State has raised a flag of caution to the rest of the country.

Perhaps Colorado is a forerunner of an America in which the true value of a breath of fresh air is a known quantity—a life-sustaining and enriching benefit which has been weighed against the costs of controlling economic growth and protecting the environment. Here, in Colorado, people have come to rest on the idea that the quality of life is founded on the daily experience of a healthful and satisfying environment, that the physical amenities of the technological society can be enjoyed only if the relationships of man to man and man to nature are not defaced by carelessness and waste.

In this context, conservation of energy resources is not an option to be considered; it is a necessary way of life. In a period of rising prices and declining resources, increasing the efficiency in the way we do things is basic to both maintaining material sufficiency and preserving the quality of life.

When the Arab oil embargo hit us totally unprepared in late 1973, energy conservation boiled down to a straightforward proposition for Americans. Domestic oil shortages created international dependency, and national economic and policy independence was threatened. After the initial jolt of widespread fuel shortages, long lines at gasoline stations, and lower thermostat settings came the second jolt: rocketing international oil prices. More recently has come the third jolt: diminishing oil and gas production in the lower 48 States. The U.S. Geological Survey has, in the past year, reduced dramatically its estimate of domestic oil and gas resources. And although our known coal resources are vast, production of coal is growing much too slowly to offset the decline in oil and gas production. New energy technologies are not now, nor will be soon, available. Synthetic fuels from coal or shale, breeder reactors, solar electric plants, and fusion electric plants are years away. Thus it is imperative that existing sources must be stretched and extended and that existing technologies must be improved and made more efficient. Energy conservation is essential.

It is, however, as the Ford Foundation Energy Policy Project has pointed out:

> . . . a mistake to regard energy conservation as an end in itself; that puts the cart before the horse. Conservation is worthwhile as a means to alleviate shortages, preserve the environment, stretch out the supply of finite resources and protect the independence of U.S. foreign policy.

In an industrialized society, extraction, processing, and use of energy and other nonrenewable resources is closely linked with environmental degradation. Increasing the efficiency of energy and material use in our society is a relatively quick, relatively inexpensive, and often an environmentally favorable alternative to the extraction, processing, and use of more energy and materials. Whether the stimulus for conservation is jawboning, higher fuel prices, or the availability of more efficient techniques and technologies, the fact remains that if the flow of energy and materials through the economic cycle is reduced through more efficient use and increased recycling, then the environmental degradation associated with that cycle will generally be reduced. Obvious, too, is the fact that such a reduction means that there will be more reserves of raw materials available for future use.

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The National Materials Policy Commission has pointed out that:

> Depletion of reserves and pollution have the same cause—failure to manage the flow materials as a cycle, resulting in a resource depleting dispersal of energy and materials into the environment as pollutants. A National policy for the management of energy and materials is needed to transform this open-ended process of wastage into a substantially closed system. The goals of environmental quality require a comprehensive system of resource recovery: the recycling of materials through the economy with minimal losses in matter and energy.

We may, in fact, be entering a new era in understanding the relationships among certain types of human endeavor and the natural world. Man, it seems, has generally progressed by uneven steps. As he has successively grasped new perceptions of how nature functions and how he can use that knowledge to bend nature to his will, man has moved stepwise to more advanced stages of technological achievement. That evolutionary pattern has been interpreted as being supportive of widely varied religious and ideological beliefs in the Western World and, in turn, has been enhanced by purposeful attempts to apply those beliefs to increase man's control over natural processes. Of course, such continual reinforcement—known technically and now popularly as "positive feedback"—has encompassed man's approach to social systems as well, resulting unfortunately in some aberrations in which man has treated his fellow man most inhumanely and nature most unnaturally.

As we step back to view currently emerging perceptions, we are struck by the growing acceptance of certain thoughts that would have been rank heresies but a few years ago.

We are faced with the long-term prospect of paying much more for energy and probably for many other materials: i.e., energy is no longer cheap.

We are, in fact, running out of certain energy and other material resources. Domestic oil and gas resources will be seriously depleted before the end of the century.

At the high rates of consumption that are occurring or are projected to occur, we can foresee serious depletion of even our more abundant critical nonrenewable resources, although the time horizon may be several centuries. In other words, we live on a finite planet with finite resources.

We are beginning to have serious second thoughts about the basic economic premise that the marketplace will, over the long term, adjust for any shortages. Higher prices for a mineral commodity are supposed to lead to increased production of the mineral, since lower quality deposits, which had previously been unworked because they were uneconomical or technically infeasible, are exploited because of more favorable economics and/or technological improvements. However, if the resources are not in the ground, higher prices will not have any effect.

We are also beginning to question another basic assumption generally made by economists: economic processes are reversible, and it only takes money to reverse the flow of economic processes. There is the general underlying belief that, if the economics were right, then we could take most of the products of our society once they have been used and recycle them, neglecting, of course, the minor losses due to less than perfect processes. It is not economic to do much of that now, the conventional wisdom has it, because virgin resources are still pretty inexpensive and, since society is fairly dispersed, gathering up the byproducts is relatively expensive. But when it becomes economical, the economists tell us, the marketplace will require such recycling and, furthermore, the dollars we put into recycling, just like the dollars are now put into disposing of our refuse, will all contribute to our GNP.

There is a serious flaw in such conventional economic thinking, however, which I believe is beginning to dawn on serious thinkers. In an imaginary world where there are infinite resources and where technological processes are perfect machines, the economic principle of reversibility would hold. But in the real world, where dollars are only surrogates for tons of steel, barrels of oil, hours of labor, etc., the flow of economic processes must obey physical laws as well. When the real world more closely resembles the imaginary world of economics—such as America from the 1870's to the 1920's—then, to a fair approximation, pure economics apply. Resource depletion can be ignored. Industrial wastes can be disposed of in a vast country without adversely affecting, in turn, the economic processes. When energy and land are cheap and there is always more farther west and when the waste products of inefficient use can be "lost," no one worries about reversing the processes.

Let me turn briefly to an analogy in physics. When man began to understand energy and matter at the macroscopic level, he could apply the powerful observations that matter was conserved and that energy was conserved. A substantial portion of the structure of classical physics and most of the industrial machines that we operate today were developed on the basis of this insight. Einstein's assertion that energy/matter was conserved and that energy could change into matter and vice versa provided a new insight and presaged the nuclear era. As we come to appreciate the implications of understanding the microscopic structure of our world, we are now building the fission and fusion energy machines of the future.

The flaw which I believe exists in conventional economic thought is that a critical physical law has not been considered in the formulation of economic principles. The Second Law of Thermodynamics—that entropy is always increasing, that energy is always moving from a state of organization to a state of chaos—has been totally ignored by most economists. As energy moves from a state of low entropy (for instance, the chemical energy bound in a molecule of methane gas) to a state of high entropy (for instance the carbon dioxide, water vapor, and heat created by the combustion of the methane), the flow is thermodynamically irreversible. The methane molecule can be reassembled again, but at a relatively large expenditure of additional energy; i.e., many more molecules of methane must be irreversibly destroyed to recreate the original molecule. Further, once the heat of combustion is expended in doing work or is otherwise lost, the heat is dispersed to a point where it becomes both thermodynamically and economically worthless; hence thermal pollution results. Finally, if there are contaminants such as sulfur in the methane or if coal is used, there are many side reactions leading generally to undesirable byproducts such as sulfur dioxide, which are generally discarded as environmental pollutants. We well know that it takes additional energy even to capture these pollutants, let alone attempt to convert them back to some more benign state.

The industrialized nations have uniformly been ignoring the ultimate practical implications of the Second Law. They have been consuming increasing amounts of nonrenewable energy and material as if somehow they could get ahead of the Second Law. Now, with higher energy prices and real fuel shortages, it does not take a Malthusian doomsday forecast or a Club of Rome computer study to raise serious questions about the way we have been doing things. If we continue to expand rapidly our use of the finite nonrenewable resources and to disperse the byproducts of their use on our all too finite planet, we will find the Second Law of Thermodynamics overtaking the principles of economics.

Energy conservation may well have a much more important and general role to play in the future. I am pleased to be here today to address this conference and to add my voice to the support of conservation of all of our nonrenewable resources, including energy.

While other Federal agencies have more central roles to play in promoting energy conservation, the Environmental Protection Agency has an important responsibility. We must aid and assist in the promotion of energy conservation measures while providing guidance to insure environmental protection as conservation measures are adopted. To fulfill both of these objectives, we work closely with other Federal agencies such as the Federal Energy Administration, the Energy Research and Development Administration, the Department of Transportation, the General Services Administration, etc.

Specifically, our research program on the environmental aspects of energy conservation is comprised of several parts which I would like to describe briefly for you today.

First, let me turn to the industrial sector, which uses the largest fraction of energy. Studies estimate that up to one-third of the industrial energy consumption in the United States can be offset through conservation measures. If it is, by the year 2000, industrial energy demands may be as much as 20 quadrillion Btu's lower than it might be under "business as usual" practices. Between today and the year 2000, more than four times as much energy could be "saved" in the industrial sector than will be used in all of the United States in 1975.

EPA has underway a major study which is examining the environmental aspects of energy conserving process changes in 13 major industrial groups. The industries include glass, phosphorous/phosphoric acid, chlorine/alkali, olefins, petroleum refining, textiles, steel, copper, cement, and aluminum/alumina. Leading process options are being studied for implementability, timing of implementation, etc., and for the adequacy of existing environmental control techniques to abate emissions and residuals from these processes. Additionally, EPA is developing environmental control techniques that are energy conserving, such as cupola off-gas heat recovery devices which reduce the cost of baghouses in metal industries.

Buildings are also large consumers of energy. It appears that the efficiency of energy use in buildings can also be improved by about one-third. National engineering associations have begun to act to encourage realization of these savings by issuing energy performance standards to buildings. The Federal Government and the Congress are also moving in this direction.

Here, however, EPA has waved a caution flag. Studies of the relationship of indoor and outdoor air quality have raised the possibility that unhealthy concentrations of pollutants may buildup within tightly closed buildings unless great care is taken in the design of energy-conservative measures. It appears that the standards proposed by the engineering societies, while a good first attempt to save energy, did not adequately address the maintenance of indoor air quality.

We are working with other Federal agencies, including ERDA and FEA, to study the potential problem of indoor air quality. An EPA study about to commence should provide results useful in the development of Federal guidelines or standards for building design and revision of existing standards.

Another EPA program is addressing the reuse of low-grade waste heat which is rejected in large quantities by electricity and steam generation. In fact, about two-thirds of the Btu's consumed in the steam cycle are rejected as waste heat. In numerous European installations, the reject heat is being used in industrial applications or district heating systems. EPA, in cooperation with agencies such as the Tennessee Valley Authority, is studying approaches to waste heat reuse, which may be applicable in the United States. Approaches such as heating fish ponds and greenhouses are being studied.

A fourth and major EPA program is resource recovery. The efficiency of our energy economy can be increased through the recovery of both Btu's and materials. By 1980, over 1 billion dry tons of solid waste will be generated each year in the United States; this is equivalent in heat content to over 1 billion barrels of oil per year, or nearly 3.5 million barrels of oil per day. In addition to the Btu content, large tonnages of ferrous and nonferrous metals and glass are present in most solid waste streams.

The Environmental Protection Agency estimates that, through 1985, energy derived from wastes could exceed in magnitude energy produced from any synthetic fuel sources or any new energy technology. By 1985, up to .5 million barrels of oil equivalent could be generated per day from waste recovery.

EPA's research, development, and demonstration programs for fuel and materials recovery from municipal wastes are pushing ahead new technologies for realizing this potential. In St. Louis, a joint EPA/utility project has brought to near commercial availability the first system to convert solid waste to electricity by cofiring refuse and coal in an environmentally acceptable manner. Other projects include other combustion techniques, pyrolysis, and biodigestion.

The programs of the Environmental Protection Agency relating to energy conservation are aimed at insuring that the environmental benefits of increased conservation are realized. The Agency is investigating efficient environmental control technologies and strategies; analyzing the environmental consequences of conservation technologies, methods, and approaches; and supporting the introduction of environmentally acceptable conservation opportunities in every sector of our economy.

In closing, I would like to emphasize again the important fact that conservation of energy and other nonrenewable resources may be the most important thrust of the current day—more important, in fact, in charting a new course for all of society than in saving Btu's or tons of ore.

3 November 1976

## Session I:

# NATIONAL ENERGY CONSERVATION STRATEGIES

René R. Bertrand, Ph.D.*
Session Chairman

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# ENVIRONMENTAL IMPLICATIONS OF HIGH ENERGY USE

Mark D. Levine, Ph.D.[1]

## *Abstract*

*The meaning of the term "high energy growth" is discussed. Analysis of energy projections made between 1972 and 1976 reveal that the OPEC oil embargo marked a significant change in attitudes about energy growth. After the embargo, most analyses of future energy growth rates were 15 to 20 percent lower than projections made before the embargo.*

*There follows a discussion of the relationship between energy use and the environment from two points of view: that of the proponents of energy conservation and that of the proponents of energy growth. Analysis of the most significant adverse impacts of energy growth on the environment lead the author to advance the axiom:*

> To the extent that high energy growth requires rapid commercialization and deployment of new and advanced energy conversion and processing technology, the probability and extent of significant environmental, health, and safety problems are greatly increased.

*A number of examples are presented in support of this statement.*

I am very pleased to be given the opportunity to speak at this symposium, especially as I applaud its purpose: the reassessment of the relationship between energy use, energy conservation, and the environment. The linkage between energy growth and the environment is a complex one, as will be apparent from my discussion today, and it is important to reevaluate this linkage in symposia such as this. Indeed, part of my message today is the complexity of the relationship between the environment and energy. I hope also to indicate ways of increasing our insight into this complexity, making sense of the complex system. I am addressing these topics from the perspective that I have gained, first as a staff member of the Energy Policy Project and then as a researcher on energy and environmental policy at Stanford Research Institute. I wish to point out that the ideas expressed in this presentation are my own and do not necessarily reflect those of any of my employers, past or present.

Let me summarize the main points of this presentation. First, I define and clarify the title, "Environmental Implications of High Energy Use." There follows a discussion of what I have termed the conventional wisdom concerning energy use and environmental impacts among proponents of energy conservation. I then turn to a review of the conventional wisdom among energy growth advocates. Finally, in good dialectical fashion, I present my own views in an attempt at a synthesis of the relationship between high energy use and the environment.

### *The Meaning of the Term "High Energy Growth"*

To discuss the implications of high energy use, we should first have a clear definition of the meaning of high energy use in the United States. Projections of future energy consumption in the United States have undergone significant change with respect to both their underlying assumptions and their results in the past 2 or 3 years. In figures 1 through 6 are shown six well-known energy forecasts and scenarios that have been published between 1972 and the present. The first three of these forecasts were made before the 1972-73 OPEC oil embargo and the rapid increases in oil prices that followed the embargo. The second three were completed after the embargo. Perusal of these six figures, which are summarized in table 1, and other projections made in the time frames before and after the embargo leads one to conclude that:

1. Before the embargo most base-case or high-growth projections of U.S. energy demand in the year 2000 were on the order of 200 quadrillion Btu's per year (about three times the energy demand in 1970).

2. After the embargo most high-growth energy scenarios were on the order of 165 quadrillion Btu's per year in 2000.

3. In the period after the embargo, increased attention to energy conservation strategies led to the development of a number of plausible low growth energy futures.

What has brought about this significant change in energy projections? To some extent, the oil embargo encouraged many to recognize the likelihood of future energy supply problems. Futhermore, higher prices of energy in the last 2 years have led many economists to suggest that long-term demand elasticities will reduce future energy demand by perhaps as much as 15 to 20 percent of the base case projections for the year 2000.

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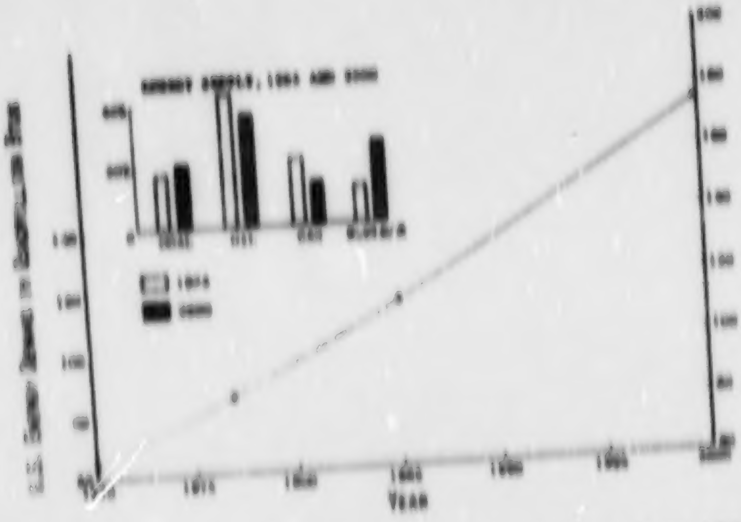

Figure 1. Associated Universities, Inc. energy forecast, April 1972.

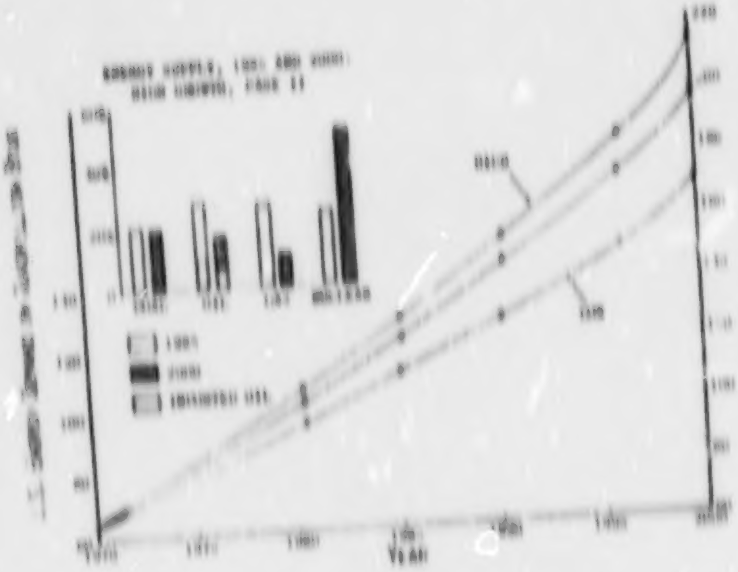

Figure 2. National Petroleum Council, energy forecast, December 1972.

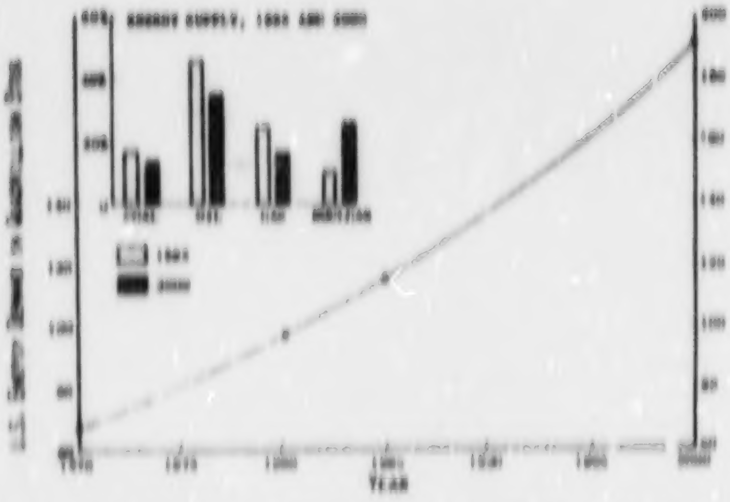

Figure 3. Department of Interior (Dupree and West) energy projections, December 1972.

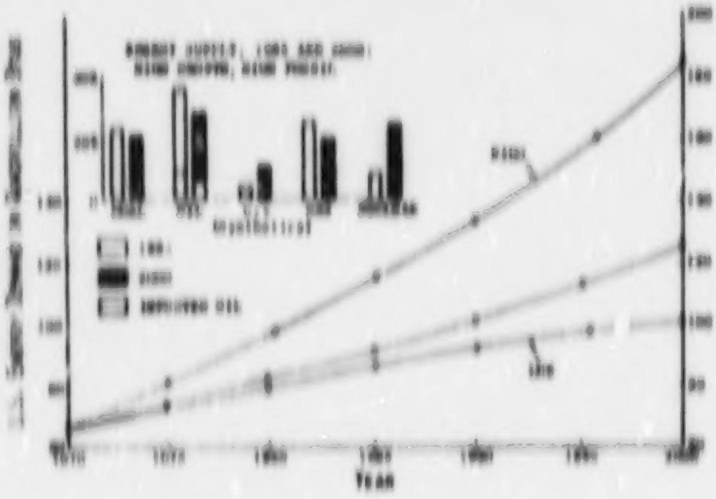

Figure 4. Energy Policy Project, energy scenarios, 1974.

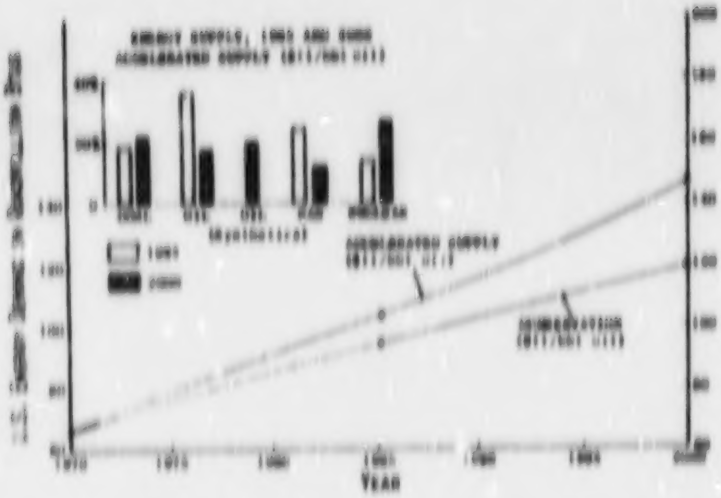

Figure 5. Project Independence Energy Forecasts (extended), November 1974.

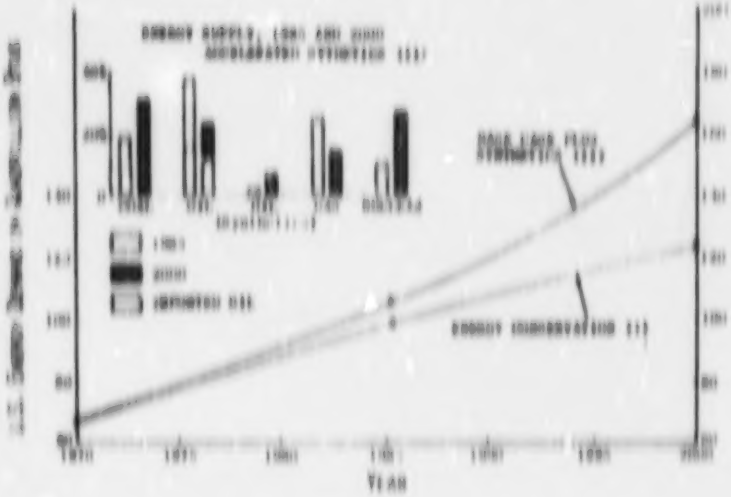

Figure 6. ERDA-48 energy scenarios, June 1975.

Table 1. High energy growth projections

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|---|---|
| • Projections made before OPEC oil embargo and oil price increases | |
| 1. Associated University, Inc., base case | 177 quads |
| 2. National Petroleum Council, high growth | 215 quads |
| medium growth | 200 quads |
| 3. DuPree and West, Department of Interior | |
| • Projections made after oil embargo | |
| 1. Energy Policy Project, high growth | 187 quads |
| 2. Project Independence, accelerated supply | 148 quads |
| 3. ERDA-48, base case without conservation | 160 quads |

It is important to differentiate between the impacts of higher energy prices and those of a long-term energy conservation strategy. Both higher energy prices and explicit energy conservation strategies reduce the energy growth rate. Higher prices tend to reduce energy demand by causing some behavioral changes that induce people to do without some accustomed activities. The effects of higher prices are most likely to be felt among the poorer economic groups, for whom energy costs are a substantial fraction of their total budget. Energy conservation, to the extent that it is accomplished in economically efficient ways, should provide savings to all consumers as well as to the environment. One of the important research needs not currently addressed adequately is the establishment of a data base and analysis that adequately distinguish the degree to which reductions in energy growth can occur as a result of economically efficient energy conservation measures as distinct from higher energy prices.

In summary, I assume that high energy growth means approximately 166 quadrillion Btu's per year in the year 2000. I assume that higher energy prices are responsible for this consumption being lower than earlier forecasts. This projection, plus or minus perhaps 10 percent, is a reflection of an energy future without substantial governmental or private sector initiatives to foster an energy conservation program that significantly reduces aggregate U.S. energy demand. Later in the discussion I return to this figure in discussing the environmental consequences of higher energy growth.

### *The Conventional Wisdom Among Proponents of Energy Conservation Concerning the Relationship Between Energy Use and the Environment*

The Council on Environmental Quality, in a report entitled "Energy and the Environment: Electric Power," in August 1973, expressed succinctly the attitude of most students of environmental impacts of energy development towards energy growth:

> Much of the environmental damage from our use of energy comes from the systems that provide the energy to the consumer. If the systems for providing energy were to function more efficiently, then the adverse environmental effects of energy production would be reduced. Similarly, if the consumer were to use energy more efficiently, ... then both energy production and environmental damage could be reduced...

The idea here is simple. To the extent that specific air pollutants and other effluents that degrade the environment are released by energy production, conversion, and end-use, reduction in energy demand will reduce environmental degradation. Of course, the same statement could be made about any other activity or consumer product. The difference is that energy production and use is responsible for a large percentage of total emissions into the environment. As shown in figure 7, 30 percent of the particulate emissions, 80 percent of the $SO_2$ emissions, 95 percent of the $NO_x$ emissions, and 60 percent of the hydrocarbon emissions from manmade sources are estimated to be derived from energy production and consumption activities. Thus, it is evident that reductions in energy growth rates cause substantial reductions in the total emissions of air pollutants in the United States.

Three generalizations are useful to summarize the point of view that attributes a substantial portion of increased environmental pollution to the growth in energy demands:

1. All energy extraction, conversion, and end-use activities are accompanied by adverse environmental impacts.

2. These energy-related environmental impacts constitute a substantial portion of all adverse effects on the environment.

3. As a result, high energy growth is likely to lead to an increased magnitude of adverse impacts on the environment.

To these three generalizations, I would add two corollaries:

1. Accelerated growth in energy consumption allows less time and fewer opportunities to safeguard the environment, as new technologies are deployed before the impacts of the technology are fully understood or adequate measures to control their impacts are developed.

2. Energy production and consumption often have secondary activities associated with them that are disruptive to the environment if adequate precautions are not taken. In many cases, the impacts of the secondary activities are significant and increase dramatically with the growth rate of energy extraction and conversion.

I will have more to say about these two points later in the presentation. Let us now turn our attention to the countervailing viewpoint regarding the relationship between energy growth and the environment.

### *The Conventional Wisdom Concerning Energy Growth and the Environment Among Proponents of Energy Growth*

Most advocates of high or moderately high energy growth admit that the environmental impacts of high energy use are likely to be somewhat more adverse than those of lower energy consumption. Their argument is predicated on the premises that environmental impacts of energy development are not severe or can be adequately controlled and that the economic and other benefits of high energy consumption outweigh the costs. In the general case, four distinct points are often made by the growth proponents:

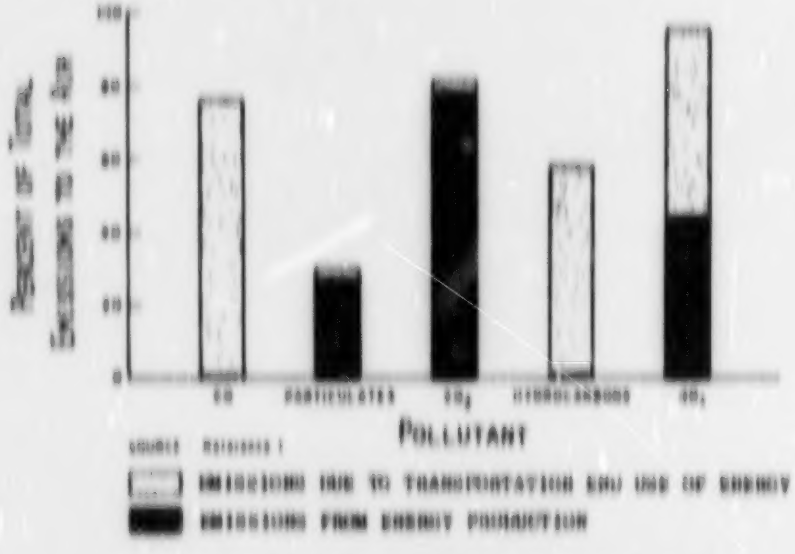

Figure 7. Estimated emissions of air pollutants by weight due to energy production and use (1970).

1. Energy use is a partial substitute for labor; as such, it is used to reduce man's toil. Thus, increased energy consumption is generally a net benefit to society.

2. New technology may be more energy intensive than the technology that it replaces (e.g., the SST); however, the use of the new technology both fosters further technological advances as well as providing direct benefits in the form of improved services. To the extent that the new, more energy-intensive technology is accepted in the marketplace, consumers have decided that it is worth additional energy and dollar costs.

3. Environmental control technology consumes significant quantities of energy, resulting in increased energy consumption; thus, control technology reduces environmental degradation while increasing energy consumption.

4. Many of the energy resources to supply high growth requirements are located in frontier areas of the United States with few inhabitants. As such, the effect of the additional energy development on people is likely to be limited.

The first two points are not directly relevant to the discussion of this paper. These beliefs, although not bearing directly on the relationship between energy development and the environment, nonetheless provide the setting for the conflict between the growth and low- or no-growth advocates regarding environmental issues. I might mention, parenthetically, that the gap between the two sides has narrowed somewhat in the past year or two. It was not too long ago that the words "energy conservation" evoked a response in some corners of government and private industry of either disbelief or great concern. Nonetheless, the point of view that tends to deemphasize the environmental impacts of energy activities should be understood as being motivated in substantial measure by considerations that are more related to the economy than to the environment.

The third point, made by proponents of growth regarding the effect on energy consumption of environmental control technology, is in my judgment a red herring. Recent studies—for example, an analysis performed by University of Michigan staff and reported in "The Energy Conservation Papers" of the Ford Foundation Energy Policy Project—have shown that additional energy consumption associated with control technologies constitutes a very small percentage of total energy consumption. The exception to this can occur when regulations are established that encourage industry to employ inefficient means of environmental control to meet standards. If intelligent and farsighted environmental policy decisions are made, there is no reason to believe that energy consumption will grow in response to environmental needs.

I defer discussion of the fourth point made by growth proponents until later in the presentation, where it is analyzed in some depth.

### *Analysis of the Relationship Between Energy Growth and the Environment*

At this point, we would do well to step back and make an assessment of where our discussion has taken us. The four points made by the growth advocates can, I think, be summarized by the statement that growth proponents generally place great emphasis on economic rather than environmental values. This is a complicated issue that takes us afield of our topic, which is to better understand the environmental implications of high energy growth. To get back on track, I consider the differences between high and low energy growth. For this purpose, I have chosen to use the two ERDA scenarios shown in figure 8: scenario II, the base case with coal synthetics and oil shale, and scenario I, which includes substantial energy conservation measures. I could just as well have chosen a different set of scenarios to depict high and low energy growth.

Analysis of these two scenarios indicates that many of the environmental impacts of the high growth case not occurring (or occurring in substantially lesser degree) in the lower growth scenario are due to the rapid development of a synthetic fuels industry. A large part of this synthetic fuels industry will probably be located in the Western States, where oil shale and much of the coal resources are found. The ERDA scenario projects a growth rate of 16 percent per year between 1985 and 2000 for coal synthetics. Oil shale is also projected to grow rapidly in this time frame. Although skeptics might question the likelihood of ERDA's high synthetic fuel growth rate, the exact rate of growth is not important to my analysis. The key environmental impacts (defined broadly to include social impacts) of this rapidly developing synthetic fuel industry include:

1. Potential urbanization problems, such as those already experienced at Gillette and Rock Springs, Wyoming, caused by rapid population influxes into rural areas not adequately prepared to deal with large numbers of incoming construction and industry workers and their families.

2. Water problems, associated with both the allocation of scarce water supplies—about which the Coloradans present are especially well informed—and potential contamination of aquifers and surface waters.

3. Aesthetic problems, especially the degradation of the presently clean air that most of the West enjoys and the construction of transportation corridors to the energy-rich regions.

4. Solid waste disposal problems, especially of oil shale residue, and revegetation of surface mined land.

5. Potential releases to the environment of toxic or carcinogenic substances not now associated with large-scale industrial or energy activities.

I cite these as critical environmental and social problems likely to occur as a result of a rapidly expanding synthetic fuels industry. A key issue, to which I now turn my attention, is that of the conditions under which these environmental problems are either more or less likely to be manageable. I have suggested that one key environmental difference between the high and low energy growth scenarios is manifest in the rapidly growing synthetic fuels industry of the higher energy future—there are other important areas of environmental differences as well. It is my judgment that the difficulties of dealing with many environmental problems are considerably exacerbated under conditions of high growth. In fact, I suggest as an axiom the following statement:

> To the extent that high energy growth requires the rapid commercialization and deployment of new and advanced energy conversion and processing technology, the probability and extent of significant environmental, health, and safety problems are greatly increased.

To illustrate this axiom, I use as an example an accelerated program of developing nuclear power in advance of public acceptance and of assurance that long-term environmental problems have been adequately dealt with. Under conditions of rapid growth, construction firms of limited experience will undoubtedly achieve substantial participation in the construction of nuclear power plants. Such a situation is highly undesirable from the point of view of reactor reliability and safety. Furthermore, considerable numbers of nuclear power plants may become operational before standards of safety have been adequately defined. The implementation of new safety standards is likely to be more difficult in a climate of rapid nuclear growth, because an industry beset with constantly changing standards is less able to meet the desired rapid development schedules. Needed solutions to the long-term high-level radioactive waste problem could come after substantial quantities of waste are already difficult if not impossible to retrieve. Commitments to research and development as well as implementation of suboptimal reactor systems—illustrated perhaps by the liquid metal fast breeder reactor—might become substantial before the necessary knowledge has been gained and analysis performed to establish which energy systems are most nearly consistent with our energy and environmental objectives.

Lest this example be misunderstood, I am not suggesting that growth of nuclear power be halted. Nor am I saying that the hazards of nuclear power are necessarily greater than those of fossil fuel electricity generation. I can equally choose an example from current fossil fuel technology development to illustrate my axiom that the host of problems inherent in the implementation of advanced technology are both more difficult to avoid and more extensive in their impact under conditions of rapid energy growth. The example is that of stack gas scrubbers for power plants.

Several years ago at least one learned scientific body pronounced the scrubber ready for implementation. The relative simplicity of the scrubber (compared to other advanced technologies), a number of successful small-scale experiments, and the satisfactory experiences of the Japanese provided strong support for the scrubber system. Unfortunately, reliability problems of the first generation scrubbers caused long delays in the implementation of this environmental control technology. We were able, for a time, to control $SO_2$ emissions to the air through the use of low-sulfur fuels. The low-sulfur fuel solution is apparently no longer viable for many parts of the Nation. In time, no doubt, the scrubbers will provide environmental benefits. The lesson that we should have learned, I believe, is that the technological fix, if it comes at all, often comes only very slowly and at high cost.

Having indicated some of the important environmental differences between the relative high- and low-energy futures, I wish also to point out that there are real environmental problems common to both scenarios. Among these are:

1. The likely adverse health effects of such poorly localized air pollutants as sulfates and nitrates, caused by energy conversion processes.

2. Land use impacts—in both urban and rural areas—of energy extraction, conversion, transmission, and use.

3. Poorly understood ecological effects that may be due to the interaction among pollutants in the environment.

4. Waste disposal problems that occur as pollutant releases to the air and water are reduced.

Once again, however, my general point is that many of these problems may be amenable to solution, given a dedication to environmental values and the necessary time to perform directed research and analysis. If we are serious about our desire to protect fragile environments and the people who inhabit them, then I suggest that we need to buy the necessary time to understand and manage adverse impacts of energy development before intensive growth in the extraction and processing of new energy resources takes place. An effective energy conservation strategy can probably buy us a good part of this time; it is, however, essential that we use the time productively to reduce the adverse impacts, as a failure to do so will otherwise serve only to delay the problems rather than to solve them. Thus, my general conclusion is that there is an important relationship between a successful energy conservation strategy and the protection of environmental values, if we are able to inject a strong environmental component into our energy research, development, and planning activities.

# IMPLICATIONS OF A NATIONAL CONSERVATION STRATEGY

Kenneth R. Woodcock[1]

### *Abstract*

*Under the National Environmental Policy Act, the Federal Energy Administration has the responsibility to assess the environmental implications of energy conservation policies, programs, and legislative proposals. Through the use of two analytic systems, PIES and MERES, the environmental impact analysis is based directly upon the projected energy impacts of proposed programs or policies. Furthermore, the economic implications of energy strategies are assessed for the preparation of inflation impact statements. This paper describes this methodology and illustrates its use in the assessment of alternative energy conservation programs and proposals. Three types of conservation strategies are discussed: energy-pricing strategies, sector-specific strategies, and combined strategies. Analytical results are presented and compared from legislative environmental impact statements prepared for the Energy Independence Act of 1975 and the Mandatory Oil Import Program.*

## INTRODUCTION

Under the National Environmental Policy Act, the Federal Energy Administration has the responsibility to assess the environmental implications of energy policies, programs, and legislative proposals. Accordingly, the agency has examined individual energy resource development and conservation programs, as well as energy-pricing policies that provide for both reductions in energy demand and incentives for additional domestic energy resource development.

The major purpose of this paper is to describe the analytical process that has been used to assess the energy, economic, and environmental implications of national energy conservation strategies. Some results of certain energy policy assessments conducted to date are provided. Finally, an overview of the implications is presented, in addition to a description of limitations of the analytical approaches that are currently available.

The analytical procedures which I will describe have been developed to assess the energy, economic, and environmental implications of energy policy proposals. The environmental impact analysis is based upon alternative energy supply and demand forecasts which are projected for the short and midterm (i.e., 1980 and 1985). In general, the environmental analysis is national in scope with regional resolution when such is possible.

The economic impact analysis presented here focuses primarily on energy prices and associated consumer cost implications of candidate policies. Further emphasis is currently being placed on the capital requirements of both energy conservation programs and resource development programs. Such analysis will facilitate the assessment of the effectiveness of capital investments in energy conservation or energy development programs.

## TYPES OF CONSERVATION STRATEGIES

The analytical approaches utilized in assessing candidate conservation strategies vary widely and the appropriateness of a procedure is highly dependent upon the energy conservation strategy that is proposed. For the purpose of this paper, various approaches to energy conservation have been categorized as follows: (1) sector-specific strategies; (2) energy-pricing strategies; and (3) combined strategies. A brief description of the strategies is provided below.

### A. *Sector-Specific Strategies*

Sector-specific energy conservation strategies strive to increase the efficiency of energy consumption within individual economic sectors, such as: transportation, buildings, industry, and utilities. Sector-specific strategies may be implemented through voluntary or regulatory approaches.

Voluntary programs, such as the administration's industrial or van pooling programs, are based on information transfer and public education programs which provide the energy consumer with the detailed information necessary to implement cost-effective energy conservation measures. Public information campaigns are also undertaken to overcome institutional or communication barriers which often prevent the marketplace from responding rapidly to conservation opportunities. The voluntary approach also includes the establishment of selected incentives for energy conservation, such as tax credits for installing home insulation.

Secondly, regulatory strategies for energy conservation impose direct requirements on activities within an economic sector to assure that energy efficient products or capital investments are provided in the marketplace.

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As with environmental requirements, the standards may be technology-forcing or may be based on other criteria (i.e., cost-effectiveness, currently available technology, etc.). An example of a regulatory energy conservation strategy is the administration's proposed energy conservation standards for residential and commercial buildings.

### B. *Energy Pricing Strategies*

Energy pricing strategies have wide-ranging implications and generally effect every sector of the economy. Energy consumption reductions are achieved by independent (voluntary) decisions on energy use by consumers and firms at all levels in the economy. At the same time, energy pricing strategies also trigger resource development responses for the specific fuel or fuels affected by the pricing strategies. The $1, $2, and $3 import fees under the Mandatory Oil Import Program, and the Phased Decontrol of Old Oil are examples of energy pricing strategies.

### C. *Combined Strategies*

Combined strategies include the mix of sector-specific and energy-pricing strategies as well as energy resource development strategies. These are generally oriented toward restructuring basic energy consumption and production patterns, so as to achieve certain energy goals. For example, legislative proposals in the Energy Independence Act of 1975 and related tax proposals were designed to: (1) reduce the U.S. dependence on foreign sources of energy; (2) increase the consumption efficiency for certain fuels; and (3) expand the development of domestic resources.

## ANALYTICAL APPROACH AND TECHNIQUES

The Federal Energy Administration has devoted much effort to the development and interpretation of energy, economic, and environmental implications of energy policies. Development of the analytical tools now used by FEA was initiated by several Federal Agencies, in conjunction with the private sector, prior to the October 1973 oil embargo. I will briefly describe these analytical tools and the procedures involved in their use.

### A. *Overview of Analytical Approach*

A flow diagram is provided in figure 1 of the analytical approach utilized for conducting comprehensive assessments of the consequences of alternative energy policies. The diagram is most appropriate for a combined strategy in which there may be environmental, resource development, energy conservation, economic policy, and foreign policy elements. However, the same approach would be applicable to an isolated energy conservation policy. A comprehensive national energy conservation strategy is likely to have associated environmental, resource development, and economic policy elements to assure a balanced and orderly transition to a more energy-efficiency economy.

### B. *Energy Policy Elements*

As shown in figure 1, a combined strategy may consist of five categories of energy policy elements:

- Environmental Policy
- Energy Resource Development Policy
- Energy Conservation Policy
- Economic Policy
- Foreign Policy

The environmental policy elements may include modifications to existing environmental legislation, such as the Clean Air Act, to mesh energy production and consumption patterns and environmental goals. Modifications that strengthen, weaken or delay environmental requirements may be required to adjust to an energy strategy that relies on an accelerated rate of domestic energy resource development while continuing to progress toward environmental goals. Furthermore, modifications to compliance schedules and degree of technological dependence may be desirable to achieve a more energy-efficient approach to environmental protection.

For example, policy elements pertaining to energy facility siting, sulfur dioxide control for coal-burning power plants, automobile emission standards, and significant deterioration were included in the Energy Independence Act of 1975.

Energy resource development policies provide for expanded domestic energy resources. This category may include:

- regulatory policies which result in the development of energy resources in areas that were not previously under development;
- energy-pricing policies to provide additional incentives for domestic resource development;
- financial policies that aid the development of needed energy production facilities; and
- measures providing for strategic and emergency preparedness in the event of future energy shortfalls or curtailments.

Energy conservation policies may, as we have discussed above, consist of voluntary or regulatory programs or energy tax and pricing policies to encourage the adoption of cost-effective energy conservation measures. These may include:

- tax credits for insulation;

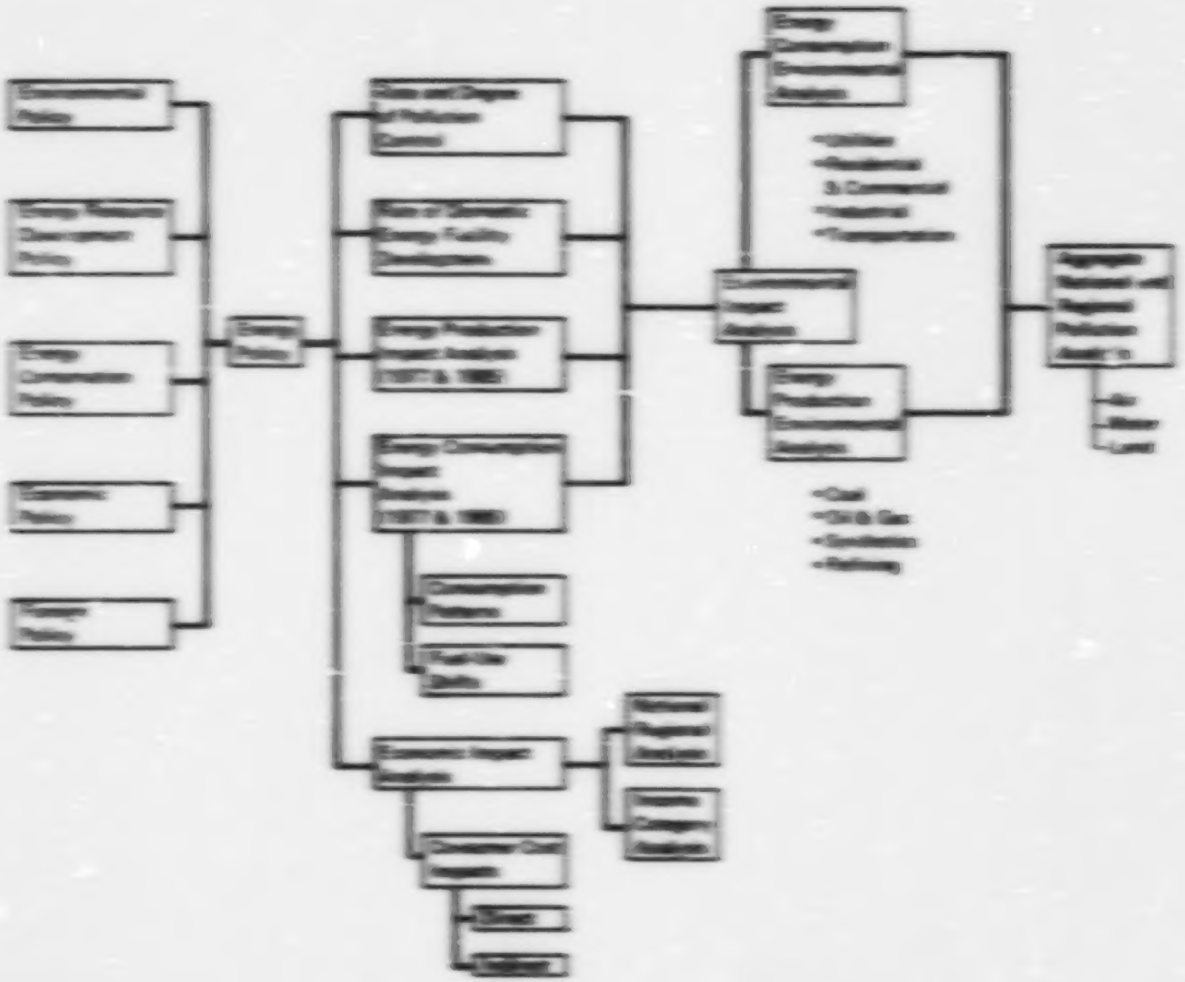
Environmental Policy
Energy Resource Development Policy
Energy Conservation Policy
Economic Policy
Foreign Policy
Energy Policy
Rate and Degree of Pollution Control
Rate of Domestic Energy Facility Development
Energy Production Impact Analysis (1977 & 1985)
Energy Consumption Impact Analysis (1977 & 1985)
Consumption Patterns
Fuel Use Shifts
Economic Impact Analysis
Consumer Cost Impacts
Direct
Indirect
National Regional Analysis
Income Category Analysis
Environmental Impact Analysis
Energy Consumption Environmental Analysis
•Utilities
•Residential
& Commercial
•Industrial
•Transportation
Energy Production Environmental Analysis
•Coal
•Oil & Gas
•Synthetics
•Refining
Aggregate National and Regional Pollution Analysis
Air
Water
Land

Figure 1. Energy/environmental/economic impact analysis of energy policies.

- public information campaigns;
- energy conservation standards for the construction of new buildings;
- efficiency requirements for vehicles, appliances, or industrial processes;
- gradual or immediate decontrol of crude oil and natural gas prices;
- import restrictions, gasoline rationing or allocation; and
- excise taxes on imported oil, all petroleum products, or gasoline only.

The economic policy elements provide means for minimizing undesirable impacts on consumers, the private sector, and the public sector. Economic policy elements may include:

- tax rebates to the consumer;
- incentives for capital investments;
- grant for assistance programs for State and local governments; and
- special provisions to assist low income persons, such as federally funded programs to improve the thermal efficiency of low income homes.

Foreign policy elements of a combined strategy could include:

- international agreements for the exchange of information concerning energy conservation and development;
- international agreements pertaining to coordinated curtailment of world energy demand in the event of future emergencies; and
- international agreements pertaining to sharing of available energy supplies in event of future emergencies.

## E. Energy Consumption Analysis

Energy consumption impact analyses assess the projected energy savings resulting from specific policy or program initiatives intended to further energy conservation. Estimates of reductions in energy consumption are based on:

- estimates of anticipated energy demand growth in the sector or subsector affected by the policy or program initiative (taking into account the likely impact of current energy prices);
- projections of changes in consumption habits due to increased energy prices (as estimated by projected demand elasticities) or tax incentives to encourage energy conserving investments;
- projections of the replacement of existing capital stock by more energy-efficient facilities, vehicles, equipment, or appliances;
- assumptions regarding economic growth and the price of energy if no action is taken;
- assessments of the overall potential for cost-effective energy savings and the likely savings to be realized as a result of specific actions (such as installing insulation in an average home); and
- assessments of the production capacity and technological capability of affected industries (such as automobile or appliance manufacturers).

The level of sophistication of the analyses performed for each of the many program or policy initiatives proposed by the administration or Congress has varied widely. It has ranged from detailed studies of energy demand elasticities, which are in some respects more advanced than any other computer modeling effort, to "guesstimates" of consumer response to measures such as energy efficiency labeling of new appliances.

The computer model used by FEA to integrate and project overall energy demand and supply levels to 1985 has relied heavily upon the results of independent analyses for inputs regarding the savings likely to result from sector-specific conservation measures. However, for overall pricing strategies and selected excise taxes, such as a gasoline tax, the FEA forecasting model is now capable of estimating energy impact internally. This analytical system enables a wide variety of factors to be taken into account simultaneously and also permits projections of numerous variations of similar pricing or tax policies. However, because of insufficient data on the complex interactions between energy demand and factors other than energy pricing, it has been impossible to use the model to project the impacts of some nonprice initiatives, such as the insulation tax credit and appliance efficiency improvement proposals. In these cases, estimates of energy demand savings are developed independently and then fed into the computer to become a part of the overall equilibrium solution that the model determines. At the same time, FEA is continually attempting to improve and expand the model through the incorporation of more sector-specific data.

An example of a sector-specific conservation initiative which FEA has analyzed is the Building Energy Conservation Standards Act, which is now receiving the consideration of the Congress. The estimates of energy savings resulting from the imposition of such standards reflect a variety of considerations. First, estimates of the energy demand by new buildings was projected to 1985 on the basis of data on construction rates in the residential and commercial sectors. These rates are affected by many factors, including economic growth, technological change, and projections of the average energy-use characteristics of new buildings. Studies were then conducted to determine the cost-effective portion of the overall potential for energy conservation in new buildings, based on actual measurement and simulation. Finally, an examination of current efforts to improve building codes provided a basis upon which realistic estimates could be made of the savings achievable through the institution of more advanced energy conservation standards. Comparison of the projected energy demand under current imposition of standards yields the incremental energy demand impact of imposing energy conservation standards for buildings.

### D. *Energy Production Impact Analysis*

Energy production forecasts, by fuel type, are based on energy demand forecasts and the availability of alternative energy resources at the projected production cost. Policy alternatives in the energy development sector are subjected to an analytical procedure analogous to that described above for the evaluation of energy conservation options.

### E. *Integration of Supply and Demand Analyses*

The Project Independence Evaluation System (PIES) has been used extensively to project energy consumption and production levels for the 1985 period (ref. 1). Recently, PIES has been further developed for estimates for 1980 and 1990.

The purpose of the PIES model is to provide an analytical tool which will generate planning estimates, depicting possible equilibrium states of the national energy system, recognizing the effect on demand of relative prices for the various fuels, the potential for fuel substitution, and the technological constraints which inhibit energy development. The PIES model is actually a framework for the integration of the outputs from a series of judgmental and quantitative submodels. For example, separate submodels exist for energy demand and for the supply of each of the fuel types. Outputs from each of these submodels are then combined by the integrating model to produce a supply/demand balance consistent with the policy constraints which are being analyzed.

The model assesses the energy requirements by fuel type for each census region and then sums these estimates for a national total. The PIES model was developed to analyze potential energy-related policies and actions of national significance, and therefore, the aggregate energy estimates for the Nation are considered far more reliable than the disaggregated regional estimates. This condition presents clear limitations for the development of reliable environmental assessments. Meaningful environmental impact assessments are regional or site-specific in dimension. Thus, the outputs of the PIES model provide a limited basis from which to project regional environmental impacts.

### F. *Economic Impact Analysis*

FEA's economic impact analysis provides for the estimates of:

- direct energy price increases by fuel type,
- direct household costs by fuel type, geographical region, and household income categories.

Furthermore, direct and indirect energy costs have been computed by the use of a stage-of-processing model developed by Data Resources, Inc. (DRI) (ref. 2). This model is used for determining indirect energy price impacts on the consumer price index (CPI).

### G. *Environmental Impact Analysis*

The environmental impact analysis to date has been focused on the determination of environmental residuals for alternative energy strategies. In addition, the number of energy facilities needed to meet alternative demand requirements are projected as an indicator of future environmental impacts.

The residual and analysis is based on air, water, and solid waste coefficients which were originally developed by Hittman Associates (ref. 3). The data has since been computerized by Brookhaven National Laboratory, under the direction of the Council on Environmental Quality, and organized into a system known as MERES (Matrix of Environmental Residuals for Energy Systems) (ref. 4). Through MERES, it is possible to estimate the residual outputs associated with the alternative supply/demand forecasts generated by PIES.

Residuals estimates have been developed for all major energy systems, and include solid wastes generated and acres of land disturbed, as well as estimated quantities of air and water pollutants emitted. The residuals estimates for the 1985 period provide an analytical basis for comparing the net changes associated with alternative mixes of energy conservation and energy resource development policies. A major limitation of the methodology is that ambient air or water quality changes cannot be predicted with desirable accuracy. That is, due in part to the likelihood of unforeseeable changes in residual-generating variables unrelated to energy matters, the analysis cannot be carried beyond estimates of energy-related residuals.

Nevertheless, the residuals approach to energy/environmental analysis is a useful tool, because the quantitative output reflects the net effect of the opposing strategies emphasizing energy conservation and/or domestic resource development policies. Qualitative statements regarding future impacts rarely achieve the same level of decision-relevant information as the residual estimates.

A second index of environmental impact may be derived by calculating the number of energy facilities (or appropriate categories) needed to meet the PIES supply/demand forecasts, and assuming some given level of impact to be associated with facilities of a specified type and size.

## IMPACT INDICATORS FOR THREE STRATEGIES

Sector specific, energy pricing, and combined strategies have been selected for the purpose of conveying the energy policy impact indicators that have been examined previously pursuant to the requirements of the National Environmental Policy Act and the administration's inflationary impact statement requirement. The three strategies provided herein for illustrative purposes are:

- the Building Energy Standards Act of 1975 (Title X of the Energy Independence Act) (ref. 5);
- the Mandatory Oil Import Program (MOIP) (ref. 6); and
- The Energy Independence Act of 1975 (EIA) (ref. 5).

A summary of the impact indicators provided in the three impact assessments is shown in tables 1, 2, and 3 for energy, economic, and environmental impact indicators, respectively.

## AN EXAMPLE POLICY ASSESSMENT FOR A NATIONAL ENERGY STRATEGY

An example of the results of an impact assessment is provided here to illustrate the decisionmaking inputs that have been developed by the aforementioned methodologies.

An environmental impact statement (EIS) was prepared on the President's proposal to establish a fee on imported crude oil and petroleum production. The scope of coverage of impacts was both national and regional. Regional classifications were developed for energy production areas, energy consumption regions and summary regions (i.e., areas to be examined for aggregate environmental impacts), to reflect the combined environmental effects of the oil import fee on energy conservation, fuel switching toward coal, and new energy production.

Table 4 is a summary of the differential energy impacts of the proposed $3 import fee, with alternatives consisting of a lower fee and a tax on gasoline use. The gasoline tax, for example, only reduces energy use, while the fees also stimulate domestic energy production. Other energy impacts that were identified in the EIS included:

- consumption effects by fuel and consumption sector for nine regions; and
- regional energy production effects for each energy source, e.g., strip-mined coal production.

Table 5 presents a nationwide summary of the changes in pollutant loadings that would occur with an oil import fee, for major air and water pollutants and solid wastes. These estimates are based on more detailed projections of pollutant loadings for production and consumption effects by region. In order to place these estimates in a more meaningful context, the results were presented in six summary regions identified in figure 3. Table 6 contains a summary description for each of these regions including:

- which pollutants will rise or fall due to the import fee; and
- the sector causing the change in emissions, e.g., fuel switching to coal in Region IV (Midwest) causes increases in sulfur dioxide.

These pollutant-loading effects are also discussed in comparison with the environmental quality problems in each of the six regions. For example, the Midwest already has significant particulate control and fugitive dust problems. Consequently, the increase in particulate emissions in that region should be of greater environmental concern than increases in many other areas of the Nation.

D. *Economic Impacts*

The costs of the oil import fee were presented in the context of the household. Table 7 shows the rise in household costs of energy by region which would be caused by the imposition of the $3 oil import fee. It shows, for example, that the Northeast would be more severely impacted than the national average, because its energy use for heating is so heavily dependent on petroleum products. Table 8 reflects another aspect of new energy costs for households with varying income levels. This comparison indicates that the import fee could have a greater impact on family incomes for the lower income group.

## METHODOLOGICAL LIMITATIONS

The analytical tools for energy and economic analysis of energy conservation strategies are relatively well advanced. The PIES model has contributed significantly to the understanding of the impact of supply and demand components of future energy plans. The Project Independence Report (PIR) and other energy policy

Table 1. Energy impacts of energy strategies

| Impact indicators | ENERGY STRATEGIES<br>EIA Title X[a] | MOIP[b] | EIA[c] |
|---|---|---|---|
| A. Short-term (1975, '76, '77, or '78) | | | |
| - Natural gas demand | x[d] | -[e] | - |
| - Petroleum demand--all sectors | x | x | x |
| - Coal demand--utilities | - | x | - |
| B. Midterm (1985) | | | |
| 1. Consumption | | | |
| - By fuel (oil, gas, coal, electricity, nuclear, other) | x | x | x |
| - By sector (residential/commercial, industrial, transportation, utilities) | x | x | x |
| - By cause | | | |
| · Auto Related | - | x | x |
| · Residential/Commercial Building Related | x | - | - |
| - By region | x | x | x |
| 2. Production | | | |
| - All fuels by production region | - | x | x |
| 3. Imports (crude products, natural gas) | - | x | x |

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[a] Building Energy Standards Act of 1976 (Title X of the Energy Independence Act of 1975).

[b] Mandatory Oil Import Program ($3 Import Fee).

[c] The President's Energy Program (Energy Independence Act of 1975).

[d] x denotes coverage in referenced sources.

[e] - denotes no coverage in referenced sources.

Table 2. Economic impacts of energy strategies

|  | ENERGY STRATEGIES |  |  |
|---|---|---|---|
| Impact indicators | EIA Title X[a] | MOIP[b] | EIA[c] |
| 1. Price impacts on petroleum products | -[e] | x[d] | x |
| 2. Direct energy costs to household |  |  |  |
| - by fuel type[f] | - | x | x |
| - by Geographic Region[g] | - | x | x |
| - by Household Income Class[h] | - | x | x |
| 3. Aggregate value of energy savings | x | - | - |
| 4. Employment |  |  |  |
| - Gas utilities | x | - | - |
| - Petroleum refineries | x | - | - |
| - Electric utilities | x | - | - |
| 5. Capital requirements | x | - | - |

[a] Building Energy Standards Act of 1975 (Title X of the Energy Independence Act of 1975).

[b] Mandatory Oil Import Program ($3 import fee).

[c] The President's Energy Program (Energy Independence Act of 1975).

[d] x denotes coverage in referenced sources.

[e] - denotes no coverage in referenced sources.

[f] Gasoline and motor oil, heating oil, natural gas, electricity, and all energy.

[g] Northeast, Middle Atlantic, East North Central, West North Central, South Atlantic, East South Central, West South Central, Mountain, and Pacific.

[h] Poor, lower-middle, upper-middle, well-off.

Table 5. Environmental impacts of energy strategies

| | ENERGY STRATEGIES | | |
|---|---|---|---|
| Impact indicators | EIA Title X[a] | MOIP[b] | EIA[c] |
| A. National impacts | | | |
| 1. Energy consumption activities | | | |
| a. Utility conversion to coal (1977) | o[e] | x[d] | x |
| b. Utility sector (1985) | o | x | x |
| c. Industrial sector (1985) | o | x | x |
| d. Household/commercial sector (1985) | x | x | x |
| e. Transportation sector (1985) | o | x | x |
| 2. Energy production activities | | | |
| a. Coal production (1977 and 1985) | | | |
| - surface mining | o | x | x |
| - underground mining | o | x | x |
| - beneficiation | o | x | x |
| - aggregate coal impacts | o | x | x |
| b. Oil production | o | x | x |
| c. Petroleum refineries | o | x | x |
| d. Natural gas production | o | x | x |
| 3. Aggregate consumption/products | | | |
| a. Air pollutants[f] | | | |
| - nationwide | o[e] | x[d] | x |
| - regional | o | x | x |
| b. Water pollutants[g] | | | |
| - nationwide | o | x[h] | x |
| - regional | o | x | x |

Table 3. (con.)

| Impact indicators | ENERGY STRATEGIES<br>EIA Title X[a] | MOIP[b] | EIA[c] |
|---|---|---|---|
| 3. (con.) | | | |
| c. Solid waste[f] | | | |
| - nationwide | o | x | x |
| - regional | o | x | x |
| B. Regional impacts (1985) | | | |
| 1. Energy consumption activities | | | |
| a. Utility sector | o | x | x |
| b. Industrial sector | o | x | x |
| c. Household/commercial sector | o | x | x |
| 2. Energy production activities | | | |
| a. Coal production (1977 and 1985) | | | |
| - surface mining | o | x | x |
| - underground mining | o | x | x |
| - beneficiation | o | x | x |
| - aggregate coal impacts | o | x | x |
| b. Oil production | o | x | x |
| c. Petroleum refineries | o | x | x |
| d. Natural gas production | o | x | x |
| e. Oil shale | o | x | x |
| f. Coal gasification | o | x | x |
| 3. Aggregate consumption/production | | | |
| a. Air pollution | o[e] | x[d] | x |
| b. Water pollution | o | x | x |
| c. Solid waste | o | x | x |

Table 3. (con.)

| Impact indicators | ENERGY STRATEGIES<br>EIA Title X[a] | MOIP[b] | EIA[c] |
|---|---|---|---|
| 4. Relationship of regional emission changes to current environmental quality problems | - | x | - |

[a] Building Energy Standards Act of 1976 (Title X of the Energy Independence Act of 1975).

[b] Mandatory Oil Import Program ($3 import fee).

[c] The President's Energy Program (Energy Independence Act of 1975).

[d] x denotes coverage in referenced sources.

[e] - denotes no coverage in referenced sources.

[f] Total suspended particulates, sulfur dioxide, nitrogen oxides, hydrocarbons, and carbon monoxide.

[g] Acids, suspended solids, dissolved solids, organics, thermal emissions.

[h] MOIP impacts included alkalinity, acidity, chemical oxygen demand, and biological oxygen demand, in addition to those references in g.

[i] Includes fixed land and incremental land impacts.

assessments have provided the Congress and the public with 10-year energy forecasts that contribute to a better understanding of the difficult and important choices that must be made.

However, procedures for environmental impact analysis of national conservation strategies have provided information of marginal relevance for public policy determination. Whereas individual environmental impact "hot spots" within the country can be projected with MERES, the ability to provide accurate ambient impact estimates for 10 years hence is, simply, not now in hand.

At the same time, this is not to say that the environmental impact methodology presented herein does not contribute to and improve understanding of the consequences of alternative energy policies. The methodology provides a means for observing the interrelationship between policy choices and the environmental factors that may be directly or indirectly affected.

Furthermore, the overall methodology for conducting energy, economic, and environmental assessments plays an important role. Too often, energy policies are evaluated from only one point of view, such as consumer

Table 4. Reduced oil imports under alternative scenarios, 1985 (expressed in terms of differences from base case)

| Factors | Millions B/D<br>$3 Fee | <br>$2 Fee | <br>Gasoline tax |
|---|---|---|---|
| Reduced energy consumption | 1.0 | .7 | 2.8 |
| Domestic oil production | 1.5 | 1.0 | -.1 |
| Shift to coal | 2.3 | .7 | * |
| Shift to natural gas | .2 | .2 | * |
| Total import reduction | 5.0 | 2.6 | 2.7 |

Table 5. Environmental impacts of oil import fee

| | Percent change from base<br>1977 | <br>1985 |
|---|---|---|
| Air | | |
| Total suspended particulates (TSP) | +1.0 | +0.4 |
| Sulfur oxides ($SO_x$) | +3.0 | -3.0 |
| Nitrogen oxides ($NO_x$) | -1.0 | -4.0 |
| Hydrocarbons (HC) | -2.0 | -5.0 |
| Carbon monoxide (CO) | -1.0 | -2.0 |
| Water | | |
| Total dissolved solids | +0.1 | -1.0 |
| Suspended solids | 0.0 | -20.0 |
| Nondegradable organics | 0.0 | -24.0 |
| Alkalinity | 0.0 | +12.0 |
| Acidity | 0.0 | -16.0 |
| Biological oxygen demand (BOD) | 0.0 | -6.0 |
| Chemical oxygen demand (COD) | 0.0 | -40.0 |
| Solid waste | | |
| Waste | 0.0 | +1.0 |

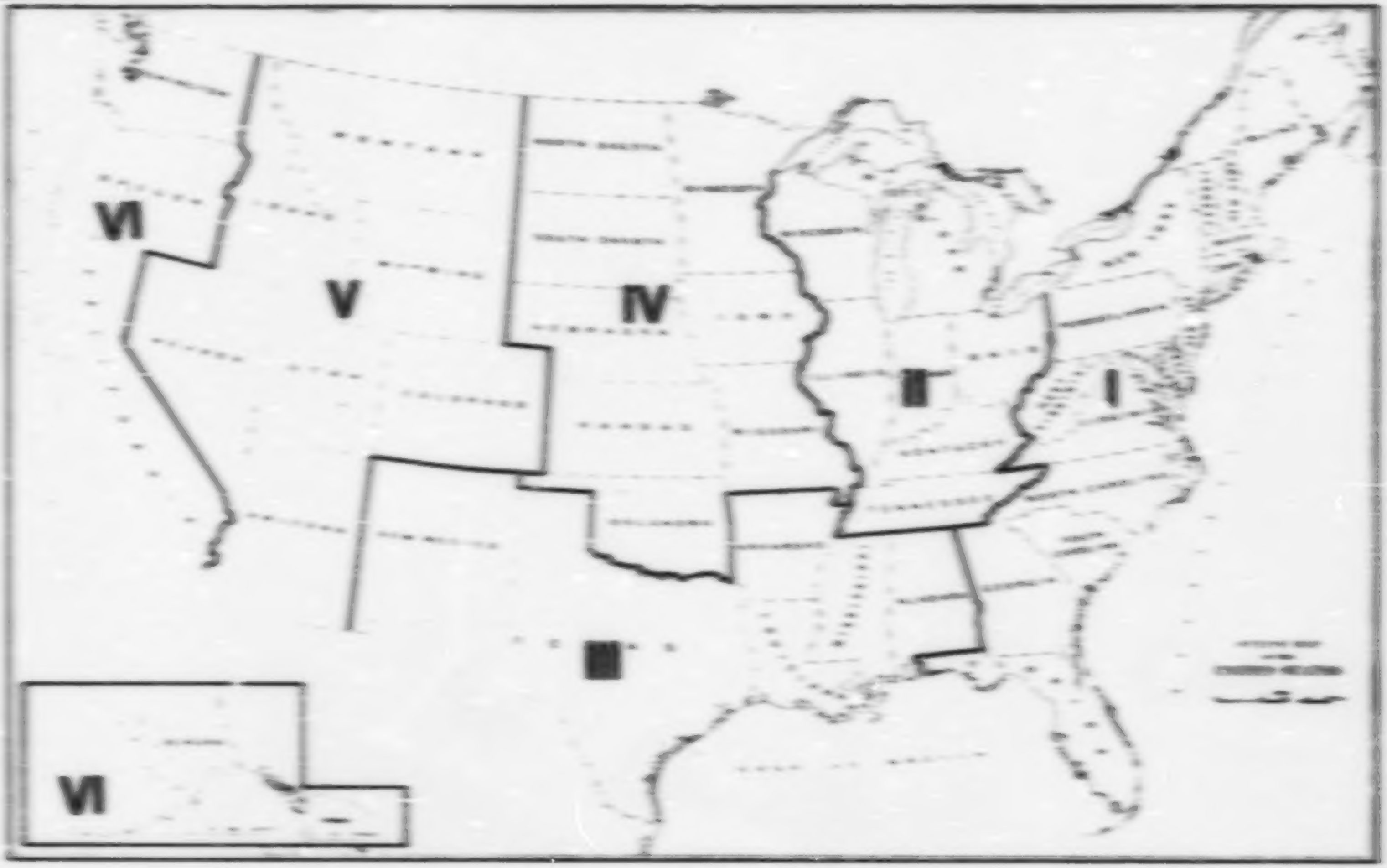
VI
V
IV
III
II
I
VI

Figure 2. Summary regions.

Table 6. Regional environmental impacts: oil import fee

| Region | Air |  |  |  |  | Water | Solid waste |
|---|---|---|---|---|---|---|---|
|  | TSP | $SO_2$ | $NO_x$ | HC | CO |  |  |
| I | Decrease<br>- Oil refining reduction<br>- Industrial demand reduction<br>- Transportation demand reduction |  |  |  |  | Decrease<br>- Oil refining reduction<br>- Industrial demand reduction | Decrease<br>- Oil refining reduction<br>- Industrial demand reduction |
| II | Increase<br>- Utility coal substitution |  | Decrease<br>- Transportation reduction |  |  | Decrease<br>- Oil refining reduction<br>(alkalinity increases due to coal mining) | Increase<br>- Coal mining increase<br>- Utility coal substitution |
| III | Decrease<br>- Demand reduction<br>- Oil refining reduction<br>- Transportation demand reduction |  |  |  |  | Decrease<br>- Oil refining reduction<br>- Demand reduction | Decrease<br>- Oil refining reduction<br>- Demand reduction |
| IV | Increase<br>- Utility coal substitution<br>- Oil refining increase<br>- Gas production increase |  |  |  |  | Increase<br>- Utility coal substitution<br>- Oil refining increase | Increase<br>- Utility coal substitution<br>- Oil refining increase |
| V | Decrease<br>- Demand reduction<br>- Oil refining reduction<br>- Transportation demand reduction |  |  |  |  | Decrease<br>- Oil refining reduction<br>- Demand reduction | Increase<br>- Coal mining increase |
| VI | Decrease<br>- Demand reduction |  | Increase<br>- Gas production increase<br>- Oil refining increase |  |  | Increase<br>- Oil refining increase<br>- Gas production increase | Increase<br>- Oil refining increase |

Table 7. Regional distribution of the increased direct consumer energy expenditures (per household) under oil import fees ($/year)

| Region | Gasoline | Heating oil | Electricity | Total |
|---|---|---|---|---|
| Northeast | 41 | 42 | 14 | 84 |
| Mid-Atlantic | 35 | 20 | 7 | 65 |
| East North Central | 47 | 9 | 1 | 57 |
| West North Central | 55 | 6 | 0 | 61 |
| South Atlantic | 51 | 4 | 0 | 55 |
| East South Central | 52 | 1 | 1 | 54 |
| West South Central | 52 | 0 | 2 | 54 |
| Mountain | 62 | 1 | 1 | 65 |
| Pacific | 45 | 1 | 5 | 51 |
| Average U.S. | 47 | 8 | 4 | 59 |

cost increases. By providing rigorous analytical assessments of the policies, the focus of attention shifts to the full societal costs and benefits of energy policy choices. Clearly, a balanced approach is needed to adjust our energy production and consumption patterns to be consistent with our domestic energy resources, societal goals, and technological capabilities.

## CONCLUSIONS

Studies conducted to date of the Mandatory Oil Import Program and the Energy Independence Act have provided some general conclusions regarding the implications of energy conservation strategies:

- Sector-specific policies show mainly positive environmental effects.
- Economic impacts of sector-specific policies are generally positive because the conservation approach is frequently the cheapest source of energy presently available.
- A mix of both beneficial and adverse environmental effects is expected under energy-pricing conservation strategies due to reduced consumption and increased resource development. Furthermore, conversions of industrial and electric facilities from natural gas to oil and coal or oil to coal also generate adverse impacts, due to the use of dirtier fuels.
- The economic impacts of energy-pricing strategies are frequently adverse unless combined with compensating economic policies that minimize the resultant consumer cost impacts.

With the range of positive economic and environmental consequences of alternative energy conservation strategies that have been observed, the Federal Energy Administration continues to identify and implement voluntary conservation programs that apply technologies which are currently in hand and which produce cost-effective savings. Policy analysis, communication with the public, program demonstration, and implementation—all of these are essential elements in the emerging national energy conservation strategy.

Table 8. Current household energy costs by income class

| | Poor, average $3,000 | Lower-middle, average $9,600 | Upper-middle, average $16,800 | Well-off, average $29,400 |
|---|---|---|---|---|
| Gasoline | $173 | $432 | $ 778 | $ 914 |
| Heating oil | 66 | 66 | 66 | 83 |
| Natural gas | 91 | 108 | 117 | 140 |
| Electricity | 160 | 203 | 259 | 319 |
| Coal | 16 | 16 | 16 | 16 |
| Total | $506 | $825 | $1,236 | $1,472 |
| Percent of average income | 16.9 | 8.6 | 7.4 | 5.0 |

Source: WCMS Survey for 1972-1973, adjusted for price increases to September 1974.

## REFERENCES

1. *Project Independence Report*, Federal Energy Administration, November 1974.
2. Data Resources, Inc., *An Energy Price Impact Model*, October 1974.
3. Hittman Associates, Inc., *Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use*, 2 vols., 1974.
4. Cf. *MERES and the Evaluation of Energy Alternatives*, Council on Environmental Quality, May 1975. The Council of Environmental Quality has also organized the preparation of a reference work based on MERES for use by preparers of energy-related environmental impact statements. See Energy Alternatives: *A Comparative Analysis*, Council on Environmental Quality, et al., May 1975 (prepared by the Science and Public Policy Program, University of Oklahoma, Norman, Oklahoma).
5. See *Draft Environmental Impact Statement, Energy Independence Act of 1975 and Related Tax Proposals*, Federal Energy Administration, March 1975. Chapter 12 gives particular attention to the Building Energy Standards Act of 1975.
6. Cf. *Draft Environmental Impact Statement, Mandatory Oil Import Program*, Federal Energy Administration, June 1975.

# LEGISLATIVE PROGRAMS IN ENERGY CONSERVATION

Maxine L. Savitz, Ph.D.[1]

## Abstract

*As part of the President's overall energy program, four legislative initiatives were submitted to Congress in 1975. The Energy Independence Act of 1975 contained three of these actions: Title X, Building Energy Conservation Standards Act of 1975, which would establish national thermal efficiency building standards for all new buildings to be implemented by States and local governments; Title XI, Winterization Assistance Act of 1975, which would provide States with funds to help purchase energy conserving materials to be installed in homes owned or occupied by low-income families; Title XII, National Appliance and Motor Vehicle Energy Labeling Act of 1975, which would require labeling of energy consuming major appliances. In addition, the President requested Congress to enact legislation that would amend the Internal Revenue Code to provide individuals with a tax credit for 15 percent of the cost of modifying their homes to conserve energy. In addition, other legislative options for achieving energy conservation in buildings and industry have been proposed by the members of Congress. The status and implication of the various legislative activities will be discussed.*

Any paper presented on proposed legislative actions during an ongoing session of Congress runs the risk of being out of date the day after it is written. This paper will be a status report as of October 1 on several pieces of legislation related to energy conservation in the end-use sector.

Almost 1,200 bills related to energy have been introduced into the 94th Congress. Of these bills, about 40 to 60 remain active, with about 20 including a decrease in fuel consumption as one of their objectives. This paper will deal with several specific pieces of legislation related to energy conservation—more efficient use of energy—in buildings and in industrial, and transportation sectors. It will not deal with bills which might achieve reduction in energy use through tax and regulatory actions to increase the price of petroleum and natural gas. Most of the legislation discussed in this paper has been passed either by the House or Senate. No energy conservation legislation has yet been passed in this session by both Houses of Congress and sent to the President. Some of the legislation discussed will have been proposed by the Administration, and some by Congress.

## BUILDINGS SECTOR

As part of the President's overall energy program, several legislative initiatives to accelerate energy conservation in the buildings sector were submitted to Congress in January 1975. The Energy Independence Act of 1975 (S. 594, H.R. 2650) contained three of these actions: Title X, Building Energy Conservation Standards Act of 1975; Title XI, Winterization Assistance Act of 1975; and Title XII, National Appliance and Motor Vehicle Labeling Act of 1975. In addition, the President requested Congress to enact legislation that would amend the Internal Revenue Code to provide individuals with a tax credit for 15 percent of the cost of modifying their homes to conserve energy. The legislative proposals in the buildings sector are an integrated package aimed at reducing energy waste in buildings. They are interdependent in that they deal with both the long- and short-term and cover all segments of the buildings sector. Title X, Building Energy Conservation Standards Act of 1975, would establish national thermal efficiency building standards for all new buildings to be implemented by State and local governments. This proposal is particularly important, since by 1985 approximately 30 percent of all residential units and 40 percent of all commercial space will have been constructed after 1974.

Adoption of energy conserving design practices could reduce the heating and cooling energy consumption of single-family dwellings by 35 percent, of high-rise multifamily structures by 24 percent and of commercial buildings by 32 percent. This legislation would result in energy savings of over 500,000 BPD by 1985, and the savings would continue to grow in the future. The legislation as proposed by the Administration would have standards developed and promulgated in three phases:

- Phase I

Secretary of Housing and Urban Development would, within 6 months after enactment of the legislation, publish for public comment proposed component performance standards for new residential buildings. The recently adopted ASHRAE 90 is an example of a component performance standard. Final standards would be developed and promulgated 6 months after publication, effective 1 year after promulgation.

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[1] Director, Division of Buildings and Industry Conservation, Energy Research and Development Administration Washington, D.C.

- Phase 2

New minimum performance standards (e.g., energy budget) for energy in commercial buildings would be developed no later than 18 months after legislation.

- Phase 3

Minimum performance standards for residential buildings would be developed not later than 3 years after legislation was enacted. These would supersede standards promulgated in Phase 1.

Research and demonstration activities to assist in the development of standards for Phases 2 and 3 would be performed by HUD, Energy Research and Development Administration, Federal Energy Administration, and the National Bureau of Standards. The standards would be developed also in consultation with Federal, State, and local government agencies, industry, labor and consumer groups. The National Institute of Building Sciences (NIBS) would be utilized.

The legislation would require States to certify to HUD that the new standards have been incorporated into local building codes and that they will be enforced. If, within a specific period of time, a State has not certified that the Federal energy conservation standard or an equal or better standard is being adopted and implemented by the appropriate local or State code, Federal financial assistance for the construction of new buildings would not be approved in that area.

Title X authorized HUD to make grants to the States to assist them in meeting the costs of developing procedures to implement energy conserving building standards.

In the spring, the Senate passed Title X essentially as proposed by the Administration as part of an emergency housing bill. It was dropped in conference to give the House an opportunity to consider the bill more thoroughly. In September, the House passed its version of energy conservation performance standards, H.R. 8650. The version passed by the House dropped the mandatory aspects of the standards bill, but directs HUD to monitor progress of the States and local governments and report to Congress within 12 months of enactment and then semiannually report the progress of States in adopting energy conservation standards. The House-passed version has only two phases—development of performance standards for new residential and commercial buildings. It omits the component performance phase. The Senate is still reconsidering Title X and other options, but as of this date has not produced a standards bill since the one passed earlier was rejected in conference.

Two proposals have been made by the Administration with regard to existing buildings—tax credits and weatherization. A tax credit, not a deduction for the cost of purchasing and installing such items as ceiling insulation, weatherstripping, and caulking was proposed. As a part of the House-passed H.R. 6860 ("The Ullman Bill"), a tax credit of 30 percent per homeowner on an investment of $500 was passed. The tax credit would expire in 3 years. This bill would also allow changes in investment credit related to energy conservation options such as insulation for commercial buildings. The Senate had passed earlier a tax credit for insulation as part of the Tax Reduction Act of 1975, but it was eliminated during conference because it was felt it should be part of energy legislation. The Senate has not yet taken new action on this tax credit.

It was recognized that there is an adverse impact of higher energy prices on low-income persons, and that many of these people would not be able to take advantage of the tax credit; thus the President proposed a winterization assistance program for low income persons. The proposed legislation would call for a $55 million program in fiscal years 1976, 1977, and 1978 to fund State winterization programs. The funding would allow for purchase of energy conserving materials for low income use. State and local officials are to be encouraged to utilize the Labor Department's public service employment program, as well as voluntary labor programs. The goal is to winterize approximately 1.5 million homes by the end of fiscal year 1978. The House-passed H.R. 6860 contained a title for weatherization assistance for low-income persons, similar to the Administration's bill. The Senate has not considered this legislation.

Another aspect of the buildings sector concerns appliances. The President proposed mandatory energy efficiency labeling of room air conditions, water heaters, refrigerators, freezers, ranges, washers, dryers, and televisions (Title XII). In the spring, the Senate passed by a large majority a Truth in Energy Act—S. 349. This bill provides for mandatory labeling, and directs the Federal Trade Commission to define average use cycles for household appliances, and to devise procedures by which average use cycles may be simulated and by which energy utilized during cycle may be measured or calculated. In September, the House passed H.R. 7014 ("The Dingell Bill"). One section of the bill requires labeling of all major appliances and has mandatory efficiency targets for appliances.

## INDUSTRIAL SECTOR

The Administration itself has not submitted any legislation to Congress regarding industrial conservation.

Current projects in industrial conservation are thought to be sufficiently comprehensive at this time. These include a voluntary program underway with the Federal Energy Administration, the Department of Commerce, and industry; the research and development program at ERDA; and industry's efforts on its own. There are two bills, S. 1908 and H.R. 8495 "Industrial Energy Conservation Act of 1975," which are currently being considered in Congress. Both bills have two identical sections. One section directs the Administrator of ERDA to establish and maintain a comprehensive research, development, and demonstration program related to energy conserving industrial technologies. It would allow for contracts and grants to private organizations and business to conduct demonstrations. The other section would allow the Administration to make loans and guarantee the payment on loans for the purchase, construction, operation, or maintenance of energy efficient equipment in facilities. The Senate bill S. 1908 would establish a mandatory efficiency reporting system and energy efficiency targets. This section is similar to one which was in H.R. 7014 (Dingell Bill, Section IV B). In voting on this bill, the House voted 220 to 187 to delete the provision aimed at reducing industrial consumption of energy. It would have set targets for the Nation's 2,000 largest industries and, although voluntary, would have required those industries to make public reports of what they were doing to save energy.

## TRANSPORTATION SECTOR

The labeling bill proposed by the Administration (Title XII) mandates labeling of motor vehicles in addition to appliances. The Senate-passed version also considered automobiles. H.R. 7014 contains provisions for automobile efficiency standards; H.R. 6860 provides for an automobile efficiency tax. The fate of these two measures in the Senate is uncertain. The Administration has addressed the issue of reducing automobile fuel consumption by obtaining voluntary commitments from automobile manufacturers to improve the production weighted average of their new cars by 40 percent in 1980. Measured against the 1974 model average of 14.0 mpg, the 40 percent goal translated into an average new car fuel economy of 19.6 mpg in 1980.

Congress is considering an "Electric Vehicle Research Development and Demonstration Act of 1975" (H.R. 8800, S. 1632). The bill passed the House in September and is currently being reviewed by the Senate Commerce Committee. The House passed version mandates ERDA to procure within 15 months 2,500 urban passenger and commercial vehicles which will meet initial standards and criteria developed within a year of enactment of the legislation. Within 42 months, 5,000 vehicles would be obtained. The emphasis of the bills is on near-term demonstration rather than development of improved electric vehicles. Due to the time constraints, lead-acid batteries would be needed in the initial phase. It is felt by ERDA that a minimum of a 3- to 5-year program is necessary to develop advanced batteries to provide vehicles with lower overall operating costs, and that a demonstration program should be delayed until battery development programs can provide the appropriate improved energy storage system.

As can be seen from the above discussion, enactment of proposed legislation—even what appears to be straightforward legislation such as tax credits for retrofit of residences—requires much time, discussion, and compromise. It is hoped that some of the above-mentioned legislation—such as building standards, tax credit, and weatherization—will be passed and signed into law in order for some of the uncertainties in energy policy to be removed and for the projected savings to start to accumulate by using energy more efficiently.

# HIGHLIGHTS OF ENERGY CONSERVATION PROGRAMS

Howard Hagler* and Harvey M. Bernstein†

## Abstract

*Highlights of energy conservation opportunities in the four consuming sectors (residential, commercial, industrial, and transportation) are presented along with a brief description of the energy demand patterns through 1985 for all four sectors. In addition, a detailed discussion of some energy conservation programs conducted by Hittman Associates in the residential and commercial sectors is presented to highlight how energy is being consumed, how energy consumption can be reduced, and the impacts associated with energy conservation measures and their implementation. Programs discussed include a technology assessment of energy conservation innovations for residential structures, a study of residential energy conservation in the Baltimore-Washington area as well as in 10 other cities in the United States, and a study to analyze factors which are related to energy use in the commercial sector.*

## INTRODUCTION

In recent years a number of Federal programs have been focused on energy conservation in the four consuming sectors: residential, commercial, industrial, and transportation. The performance of these programs has been timely in helping to identify energy consumptive trends as well as ways to minimize consumption, and in a number of cases has resulted in the development of national energy policy. The energy conservation programs have covered a wide range of topics, embracing on the concepts of energy use indexes, demonstration projects, life cycle analyses, improved processes, new equipment, retrofitting old equipment, etc. This paper highlights some of the major energy conservation opportunities in all four consuming sectors and then presents a more detailed description of some of the current energy conservation programs in the residential and commercial sectors. Prior to highlighting the programs, a brief description of the energy demand patterns for all four consuming sectors is presented.

## ENERGY DEMAND PATTERNS IN THE FOUR CONSUMING SECTORS

In 1972, the U.S. aggregate energy demand was 72.1 quadrillion Btu's (ref. 1). Of this total, the four major end-use sectors consumed energy in the following proportions:

Residential
(10.5 quadrillion Btu's) . . . . . . . . . 14.5 percent
Commercial
(6.2 quadrillion Btu's) . . . . . . . . . . 8.6 percent
Industrial
(21.9 quadrillion Btu's) . . . . . . . . . 29.9 percent
Transportation
(17.5 quadrillion Btu's) . . . . . . . . . 24.3 percent

The remaining 23 percent of the 1972 demand was comprised of two auxiliary end uses: nonenergy uses of energy resources (petrochemical feedstock, etc.), and losses in the generation and transmission of electrical power.

In its recent report on the potential for energy conservation in the United States, the National Petroleum Council (NPC) disaggregated the 1972 energy demand by end uses presented above, and made energy demand projections through 1985 (ref. 1). These projections reflect a continuation of past and current trends, and embody a number of economic assumptions (too numerous to mention here), which resulted in projecting that the 1972 U.S. energy demand will almost double by 1985. The projected increase is essentially attributed to increasing nonenergy uses of energy resources (e.g., petrochemical feedstock) and to energy consumed due to electricity production and distribution losses. These represent 31.5 percent of the 1985 U.S. projected total demand and an increase of 37 percent over the portion they consumed in 1972.

In view of these trends, it is clear that in order to maintain our Nation's economic health and standard of living without jeopardizing the independence of our foreign policy activities, we must exploit every possible opportunity to use energy more wisely and efficiently. Several ways to achieve this end are described in the following section.

## HIGHLIGHTS OF ENERGY CONSERVATION OPPORTUNITIES BY END USE SECTOR

In this section, highlights of some of the opportunities for conserving energy are listed for each of the four end-use sectors. Each sector is further divided into options applicable to the sector as it now exists, and options applicable to future additions to each sector (homes, autos, plants, buildings). This listing is brief and is merely intended to reflect the various types of energy conservation opportunities available. A more detailed discussion of some of the energy conservation programs in the residential and commercial sectors, based on work performed by Hittman Associates, follows this section.

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Residential Sector
- Existing Homes
  - Add storm windows and storm doors,
  - Use forced attic ventilation when attic temperatures exceed 100° F,
  - Add ceiling insulation,
  - Apply caulking and weatherstripping around doors and windows,
  - Insulate exposed basement wall,
  - Set thermostats back.
- New Homes
  - Reduce window area,
  - Specify installation of storm doors and windows,
  - Increase wall insulation,
  - Install white roofing shingles instead of black.

Commercial Sector
- Existing Buildings
  - Establish 65° F as maximum indoor setpoint temperature,
  - Establish 10° F setback during unoccupied hours,
  - Insulate ceiling,
  - Reduce lighting levels,
  - Shut down cooling system 1 hour before closing.
- New Buildings
  - Avoid use of terminal reheat cooling systems,
  - Determine building orientation to optimize use of solar energy,
  - Specify double glazing,
  - Use ventilation air and lighting heat recovery,
  - Use steam condensate heat recovery.

Industrial Sector
- Existing Plant and Equipment
  - Institute energy management program,
  - Insulate bare steam lines,
  - Return steam condensate to boiler plant,
  - Flash high-pressure condensate to produce low-pressure steam,
  - Eliminate leaks in gas lines,
  - Lower pressure in compressed air lines to minimum,
  - Use engine exhaust heat for steam generation,
  - Check for proper fuel temperature for fuel oil atomization.
- New Plant and Equipment
  - Substitute coal derivatives for oil and gas derivatives as feedstock for plastics industry production whenever possible,
  - Implement raw materials with lower primary energy requirements wherever possible,
  - Improve grinding processes in cement production,
  - Build cement kilns with heat recovery technology,
  - Invest in improved technology to improve the efficiency of electrolytic reduction cells used in smelting alumina to aluminum,
  - Increase use of sawmill residue and recycled stock in paper production,
  - Increase use of recycled rubber hydrocarbon.

Transportation Sector
- Existing Automobiles
  - Auto maintenance,
  - Carpooling,
  - Driver behavior improvements.
- New Automobiles
  - Stratified charge engine,
  - Smaller, lighter autos,
  - Diesel engines,
  - Battery powered auto,
  - Reduced rolling resistance,
  - Reduced aerodynamic drag,
  - Transmission modification,
  - Axle ratio modification.

## ENERGY CONSERVATION PROGRAMS IN THE RESIDENTIAL SECTOR

This portion of the paper will address two of the more recent energy conservation programs performed by Hittman Associates in the residential sector for the Department of Housing and Urban Development, and briefly mention a third ongoing effort.

### *Residential Energy Conservation in the Baltimore/Washington Area*

The objective of this study (ref. 3) was to examine in depth the most significant ways in which energy is consumed in our homes, and to evaluate various techniques that can be employed to reduce that energy consumption.

The analysis of residential energy conservation measures followed the basic methodology outlined below:

1. The Baltimore/Washington area was selected as the geographic and climatic region to be studied in depth.
2. "Characteristic" dwellings were defined, using demographic data, for the most prevalent single-family, townhouse, low-rise, and high-rise structures. These dwellings were used as a basis for evaluating the merit of energy-conserving modifications.
3. The program was directed toward energy savings possible in new construction only.
4. All structures were assumed to use good quality construction.
5. One weather year (1964) was selected as representative of the Baltimore/Washington weather.
6. A constant daily occupancy and appliance/lighting schedule was used.
7. A computerized simulation of the characteristic residences was used, subject to computerized simulation of the weather, internal loads, and occupancy loads to calculate the precise energy requirements for the characteristic residences.
8. The simulated residences were modified to include certain energy conserving modifications, and the residence energy requirements were recalculated for the "modified" structure.

Energy conserving modifications to the "characteristic" dwellings were limited to those which:

1. would save sufficient energy to pay for themselves within a 10-year time span;
2. would be within current construction capability and be aesthetically acceptable from an architectural standpoint;
3. would not significantly alter the lifestyle of the residents; and
4. would be applicable primarily to new structures.

The computer program used in the energy calculations was originally developed for the U.S. Postal Service for the analysis of energy balance in post office buildings. However, this program was not usable in its original form for residential buildings. Therefore, it was modified and its capabilities were amplified.

Following the above methodology, the results of the study identified quantitatively methods whereby energy consumption can be reduced within single-family and multifamily residences. Though the analyses were performed for residences characteristic of current construction in the Baltimore/Washington area, the results can be extended generally to both old and new construction, and to residences in different geographic areas (with limitations).

Three areas of energy consumption within residences were identified for the study: the design and structure, the internal loads (lights and appliances), and the comfort control systems. A description of the observed results of the study (ref. 2) with respect to these three areas follows:

*Design and Structure*.—The potential for energy savings in the area of design and structural modification is dependent on the climatic conditions, and on whether the residence has already been constructed or is still in the design stage. For new construction, those modifications applicable to colder or warmer climates can be readily incorporated. However, for existing structures, modifications such as increased insulation in walls and floors may prove to be impractical. Emphasis should therefore be placed on modifications that can be more easily accommodated such as addition of storm windows and storm doors, caulking and weatherstripping, and placement of window shading. Particular attention should be given to reducing the amount of air infiltration through cracks in siding, windows, and doors. All existing residences should be checked for areas of air infiltration.

*Internal Loads*.—The modifications identified for reducing the energy consumed by lighting and appliances are those controlled primarily by consumer choice and would be applicable to both new and existing residences regardless of their geographic location. However, the ability to implement these modifications may be restricted by the unavailability of gas in some areas and the cost of replacing existing equipment while it is still operable.

*Comfort Control Systems*.—The applicability of modifications identified for reducing energy consumed by the comfort control systems would be influenced by the climatic conditions associated with the geographic area of the residence, and by the type and age of the residence. For example, modifications associated with cooling may be not applicable for northern climates and the conversion of one form of heating to another in an existing building may be impractical. However, all residences in all geographic areas could conserve energy by lowering the thermostat setpoint for heating and raising it for cooling, and by specifying high-performance heating and cooling equipment.

### *Technology Assessment of Residential Energy Conservation Innovations*

Our national experience has taught us that the side effects or secondary impacts of a new technology's implementation frequently are unexpected and adverse. The objective of this study (ref. 3) was to examine the desirability to the Nation and to the consumer of selected technical innovations intended to reduce energy consumption in the residential sector.

The innovations studied were chosen at the outset of the study. For single-family housing, they include storm windows and storm doors, furnace energy recovery devices, and open-air-cycle air conditioning. For multifamily housing, innovations studied were ventilation energy recovery systems and double-glazed windows. These particular innovations were selected from those whose technical performance has been studied as part of a continuing program on energy conservation research sponsored by the Department of Housing and Urban Development, in conjunction with the National Science Foundation and the Environmental Protection Agency.

This technology assessment has three objectives:

1. To quantify the energy, economic, materials, and air emissions impacts of the selected single-family and multifamily modifications intended to reduce energy consumption;
2. To determine the cost effectiveness of the consumer's investment in the selected innovations;
3. To examine and evaluate government policy options capable of promoting mass implementation of those innovations found desirable from a national viewpoint.

An underlying objective was to develop the capability to perform technology assessments in the area of residential energy conservation. Other very important modifications, both technical and operational, remain to be addressed in this type of study, including ceiling and wall insulation, reduced window area, heat pumps, and various solar systems.

The performance of this study followed seven conceptual steps (ref. 3):

1. To establish the energy conserving modifications to be studied and the impact areas of principal concern. The impact areas include material resources, energy resources, environmental impact, and economic impact.
2. To develop a baseline against which results in the four impacted areas may be measured. This involves a detailed characterization of each of the modifications studied, including determination of the materials and energy consumed in their manufacture, evaluation of their current use ("saturation") in various regions of the country, estimation of the energy to be saved per dwelling unit by region, determination of the cost and manpower involved in their manufacture, determination of the annual dollar savings to the consumer resulting from the energy saved, and examination of existing policy and institutional structure relevant to the study.
3. To evaluate Federal, State, and local policy options for promoting the installation of energy conserving modifications. This involves a study of their ease of adoption (including precedents in previous legislation) and their effectiveness in promoting the modifications, i.e., how they influence the rate of introduction of energy-saving modifications. It also calls for testing the effect of policy options on the cost effectiveness of typical innovation purchases.
4. To adapt an existing computer program (developed by Hittman Associates, Inc., under a previous technology assessment program for the National Science Foundation) to perform the detailed calculations and bookkeeping operations in each of the four impacted areas.
5. To develop plausible case studies based on rates of introduction consistent with feasible limits of innovation applicability, industrial production capacity, and the minimum elapsed time before change could occur as a result of this study.
6. To determine the magnitude of potential impact in each of the four areas and evaluate the consequences of those impacts.
7. To recommend action by the Federal Government to promote implementation of those innovations found desirable from a national viewpoint.

The life cycle impacts of the innovations included case study evaluations of energy, economic, air emissions, and materials impacts. Evaluations are supported by quantitative examples drawn from 83 computerized case studies.

The cost effectiveness of typical innovation purchases is determined by cash flow analysis. It includes initial cost, sales tax, finance charges, installments, fuel bill savings or increased rent, maintenance and operating costs, property taxes, and income tax advantages in determining the cash payback period and total net cash return of innovations as investments in various regions of the country. Selected government policy options were tested in the study for their effect on these cost-effectiveness parameters.

The major conclusions reached during this study are as follows:

1. Increased implementation of storm doors and windows on new and existing homes can be achieved without serious negative impacts.
2. The furnace energy recovery device is potentially as conservation effective and cost effective as storm doors and windows.
3. Open-air-cycle air conditioning can save very little energy, and does not appear cost effective.
4. Ventilation energy recovery can save very little energy and is limited in application.

5. Increased new multifamily implementation of double glazing can achieve modest energy savings with no adverse life cycle impact and is cost effective in selected areas.

***Residential Energy Conservation—Detailed Geographic Analysis***

The overall objective of this study is to quantify the impact of selected single-family and multifamily residence modifications on residential consumption for different geographical areas. This study, for HUD, has just recently started and will identify the energy consumption associated with characteristic residences for 10 geographic areas of the United States and also identify the energy savings associated with structural modifications. The 10 selected areas of the United States that will be used for this study are:

Minneapolis, Minnesota
Chicago, Illinois
Boston, Massachusetts
Denver, Colorado
St. Louis, Missouri
San Francisco, California
Atlanta, Georgia
Los Angeles, California
Houston, Texas
Miami, Florida

The overall study is very similar to the study described earlier for the Baltimore/Washington area, with one exception; the primary objective of this study is to identify the differences in energy consumption attributed to location and climatic differences. The study will result in reports being prepared for each of the areas being studied as well as an overall summary report.

## ENERGY CONSERVATION PROGRAMS IN THE COMMERCIAL SECTOR

This portion of the paper will address an energy conservation program recently completed by Hittman Associates in the commercial sector for the Federal Energy Administration.

***Factors Related to Energy Use in the Commercial Sector***

The objective of this study (ref. 4) can be divided into the following four areas of investigation:

1. To quantify the commercial space inventory in the Central Business Districts (CBD's) of two major U.S. cities (Baltimore and Denver) and three major suburban shopping malls. This quantification was to include an assessment of the aggregate amount of commercial space in each location, as well as an assessment of the physical characteristics of the commercial space in each location (such as height, age, equipment type, etc.).
2. To investigate and identify those institutions and institutional practices which led to the current rates of energy consumption as well as those which stood as constraints or impediments to energy conservation through retrofit in each location.
3. To gather energy consumption data for a subsample of the Baltimore CBD buildings, and to use these data to:
   - Define average empirical energy use rates for sets of buildings with different commercial uses, and establish the range of energy use rates shown for each commercial use type.
   - Investigate whether or not empirical relationships could be shown between building physical characteristics and energy consumption rates.
4. To develop and analyze a set of possible government policy options which are capable of inducing retrofit for energy conservation in the commercial sector.

The overall study identified a number of observed trends in the Baltimore and Denver CBD's, some of which may be generalized to other CBD's and are identified here for each of the four major parts of the study (ref. 4).

*Physical Characteristics*

Twenty-six hundred buildings were surveyed in Baltimore and Denver and resulted in the following observations:

1. Office activity is the overwhelmingly predominant use of commercial building space in both CBD areas. For the two cities studied, the office space was above five times as large as the next use (see figure 1).
2. Small stores and department stores are the most predominant uses of retail space. In each of the cities studied, these two uses together comprised approximately 70 percent of the CBD retail space.
3. The trend for the future of CBD areas seems to be toward greater utilization of space for nonretail activities. From observations in both Denver and Baltimore, only the nonretail uses have experienced new CBD construction activity after 1961. Retail space construction has been in the outlying suburban areas (such as the building of enclosed shopping malls like the Villa Italia Mall in Denver).
4. Growth in CBD retail space virtually stopped about the year 1960.
5. Larger, newer commercial establishments tend to use distributed hot air for heating. Smaller, older

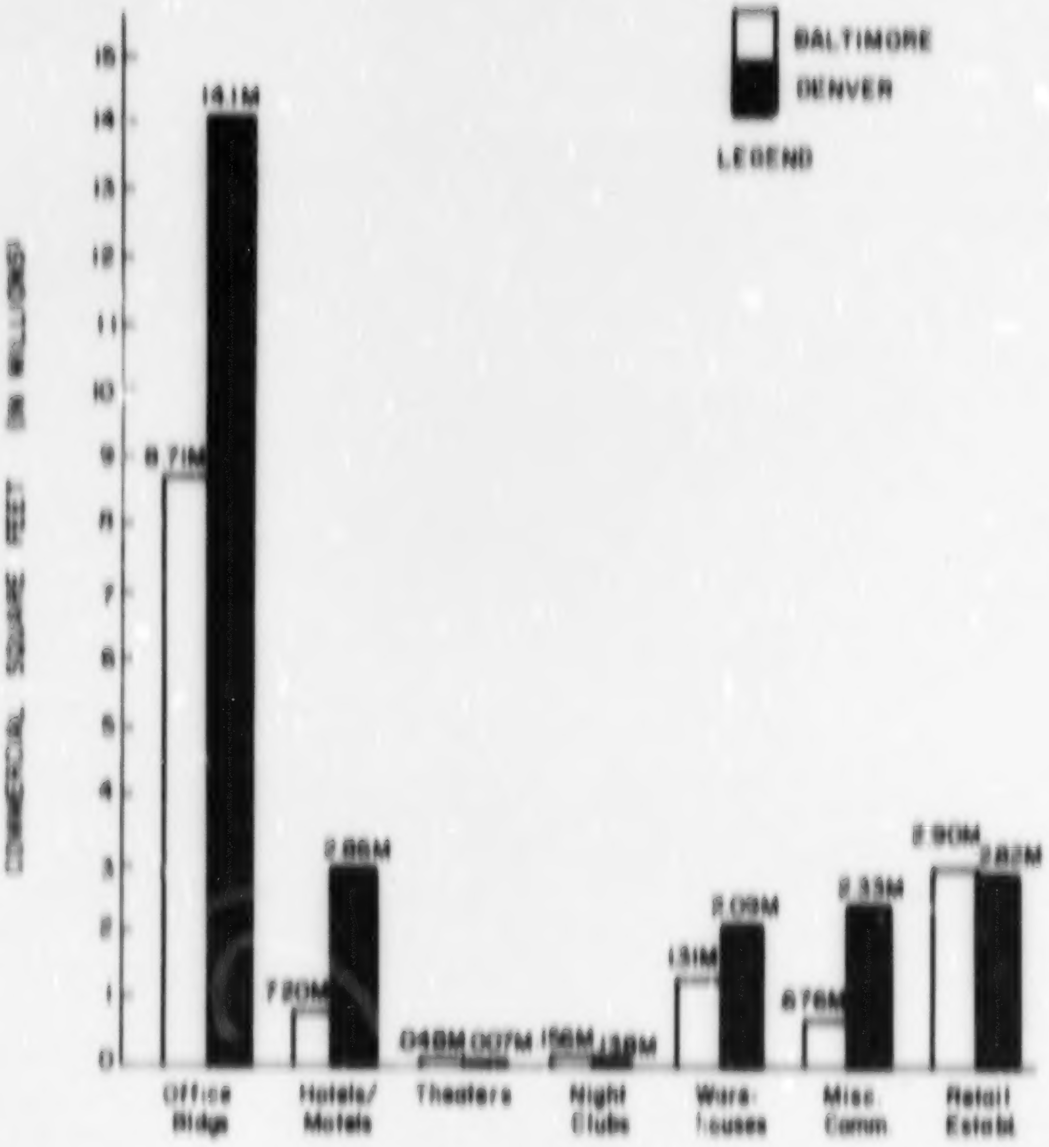

Figure 1. Commercial square feet by location and use.

establishments tend to use radiant steam or radiant hot water.

6. Fuel used for space heating is dependent on local energy market conditions.
7. Offices and hotels, which are predominant in Denver (see figure 1), are normally free-standing structures, and have the highest exterior glass ratios of all the commercial and retail establishments when expressed as a fraction of total floor space.
8. Baltimore CBD data showed that the glass fractions (with respect to floor space) for offices built after 1960 were approximately 10 percent higher than for those built before 1960.

*Institutional Factors*

Building codes, building design and construction practices, and building regulatory practices have led to the current energy consumptive trends in the commercial sector. Some of these practices can be identified as follows:

Building Codes

- Promulgated to protect citizens from fire hazards and structural failures from poor workmanship;
- Designed with emphasis placed on reliability resulting in large safety factors and general overdesign in sizing building components;
- Written such that lighting and ventilation levels were specified to protect public health and safety—these must be reassessed to determine impacts on building energy use.

Building Trade Practices

- Extensive use of exterior glass contributes to heating and cooling system loads;
- Buildings are designed for minimum first cost;
- Life-cycle operating and maintenance cost for equipment and systems are not specified;
- Performance and reliability servicing of equipment after installation is not the engineers' responsibility.

Practices of Regulatory Bodies

- Utility rate structures are regressive and have helped to encourage excessive energy use.
- Master metering has been installed in many buildings that were previously individually metered.

*Energy Consumption*

Energy consumption data were collected for 381 buildings in the Baltimore CBD during the 12-month period of May 1974 through April 1975.

The mean annual energy use rates (expressed in Btu/ft$^2$/yr) found for the 17 commercial use types are given in table 1, along with the number of establishments and number of square feet of commercial space upon which each energy use rate is based.

In addition to the energy use rates, the following conclusions were drawn from the analysis of Baltimore CBD energy use data:

1. From an energy use standpoint, commercial buildings cannot be considered as a monolithic whole. There exists substantial variation along numerous lines in buildings' energy use rate.
2. Steam cooling results in significantly more in-structure cooling energy use than electrical cooling. Other factors, such as utility system load factors and building owners' economic concerns mitigate this result.
3. Baltimore CBD energy consumption rates showed that energy use rate was dependent upon building age, with older buildings having uniformly lower energy use rate values than the average for their use category. It was assumed that age represented a surrogate for such variables as materials used, design methods employed, and construction practices.

*Policy Options*

Eight policy options and their potential impacts with regard to energy savings, costs to the building owners, and costs to the government were discussed in the Hittman study for FEA (ref 4). These eight policy options are listed below to identify the direction the results of this study took:

1. *Tax Credit Policy Option*—Enact legislation granting a 15 percent tax credit to building owners who install qualifying retrofit equipment.
2. *Accelerated Depreciation Policy Option*—Enact legislation permitting a 3-year depreciation schedule for qualified retrofit equipment.
3. *Excise Tax Policy Option*—Enact legislation creating an energy excise tax with an increasing tax rate for consumption above a decreasing standard.
4. *Small Business Loan Policy Option*—Expand the loan program operated by the small business administration to include special loan funds for retrofit of small business establishments.
5. *Disclosure Policy Option*—Enact legislation requiring a building owner to disclose the previous 5-year energy-use history of his building to any potential buyers before the sale.
6. *Public Information Policy Option*—Undertake a public information program to educate building owners and operators regarding energy concerns.
7. *Utility Rate Restructuring Policy Option*—Enact legislation instructing the Federal Power Commission to remove the regressiveness from their rate structures, and encourage private utility companies to do likewise.

Table 1. Average EUI[a] of Baltimore CBD commercial building groups (ref. 4).

| Use type | Average EUI | Number of establishments sampled | Number of square feet sampled |
|---|---|---|---|
| Restaurants | 300,000 | 25 | 70,991 |
| Night clubs | 253,192 | 23 | 42,479 |
| Drug stores | 232,672 | 6 | 15,303 |
| Food stores | 206,986 | 5 | 5,704 |
| Department stores | 164,417 | 27 | 1,142,175 |
| Hotels/motels | 146,597 | 6 | 950,400 |
| Banks | 144,634 | 15 | 68,743 |
| Offices | 124,647 | 87 | 6,477,049 |
| Personal services | 117,318 | 26 | 46,299 |
| Small stores | 95,378 | 132 | 381,443 |
| Theaters | 75,844 | 2 | 51,600 |
| Warehouses | 61,973 | 29 | 439,470 |

[a] EUI: Energy Use Index, expressed in Btu/gross square foot/year.

8. *Direct Subsidy Policy Option*—Enact legislation enabling building owners to receive a subsidy for 20 percent of the cost of qualified retrofit installations.

For a more detailed discussion of these policies and their potential impacts, the reader is directed to reference 4.

## CONCLUSIONS

Energy consumption in the consuming sectors still needs to be curbed and reduced to levels deemed appropriate by Federal officials and many of the experts in the field of energy utilization. Programs such as those briefly discussed in this paper help to meet and identify many of the causes for our continued inefficient use of energy. It should be noted that there are a number of other studies, too numerous to mention here, that have made significant contributions to conserving energy in the consuming sectors. One study in particular, entitled "Guidelines for Saving Energy in Existing Buildings" (ref. 5), was recently published by the FEA and will help building owners, manager, operators, and occupants to conserve and manage energy usage without having to invest significant amounts of money to do so. Information obtained from studies such as those discussed in this paper should be used in providing input to energy policy makers and planners.

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# THE EFFECT OF ENERGY COMPONENTS ON SYSTEM COSTS AND EFFICIENCY

T. J. Thomas, Ph.D.[*]

## *Abstract*

*It is the premise of this paper that the cost and efficiency of proposed energy delivery system components must be evaluated within the context of the system with which they are to be used, as the system inefficiencies can scale up the costs of the proposed components. Specifically, there exists a number of technologies by which the sulfur oxide emissions from the burning of coal can be minimized. These technologies are attractive on paper, but their use may greatly affect total system cost and efficiency.*

*A methodology is presented by which total system cost and efficiency may be easily calculated. Individual component contributions to total system cost and inefficiency are also developed by this methodology.*

*This methodology is applied to six example energy delivery systems based upon the delivery of 1 MWe of electricity (from coal) to a midwest area. Each system has some form of sulfur removal, and each represents the most optimal system of a set of systems using nearly the same components in various combinations.*

*The results show clearly the effect of major system components, including sulfur removal techniques, on total system cost and efficiency. Potential areas for improving system efficiency at little or no cost are delineated.*

## INTRODUCTION

Environmental gains in the past decades have been achieved in part through the substitution of clean fuels for coal. However, the recent OPEC price hikes, arriving with a depletion of national resources of clean fuels, have made clean fuels expensive, and even unavailable. The need for a fuel which is relatively abundant, available, and inexpensive is resulting once again in a growing utilization of coal.

Many processes have been developed to minimize the sulfur oxides emissions from the burning of coal. A proper evaluation of the effects of these processes upon the delivered cost of energy and the delivery efficiency requires that these processes be evaluated within the context of their proposed usage. In short, what needs to be examined is the conservation consequences of proposed environmental benefit systems.

Future users of coal-based fuels will have several technologies available by which their emissions of sulfur oxides can be decreased to acceptable levels. These include:

1. cleanup of the stack gases;
2. utilization of low sulfur coal;
3. liquefaction of the coal, with sulfur removal; and
4. gasification of the coal, with sulfur removal.

Each of these technologies introduces a cost and inefficiency to the energy delivery system to which it is applied. What is presented in this paper is a consistent methodology by which an energy delivery system can be evaluated, and the results of the application of the methodology to six energy delivery systems that utilize the sulfur oxides control technologies.

## THE COST MODEL[†]

The Cost Model is based on "technology modules" and "energy delivery systems." A technology module is a distinct step in mining, transportation, or processing of coal to produce energy. An example of a technology module, shown in figure 1, is the Hy-Gas, Steam-Iron Process, which produces pipeline-quality gas of approximately 1,000 Btu per cubic foot. In all cases, except coal mining, a technology module is described by technical and economic parameters which reflect all activities and costs associated with that technology module. In the case of mining, the cost of the technology module is the cost of the coal. In all other technology modules the cost of the fuel is excluded from the estimated costs of the technology module, as developed in the individual technical studies. In all cases, the cost of operating a technology module includes the cost incurred for the disposal of all byproducts of the process, whether those byproducts are normally considered useful or are normally considered as wastes. No credit was allowed for potentially useful byproducts, but all costs for the disposal of waste byproducts are included in the operating costs.

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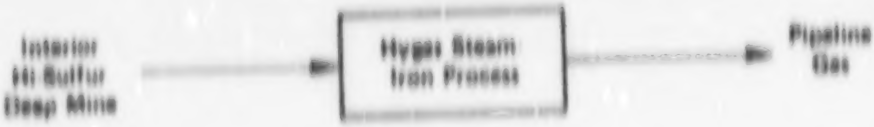
[*] Research Environmentalist, Battelle Columbus Laboratories, Columbus, Ohio.

[†] This is based upon work performed with internal funds through the Battelle Energy Program.



INPUT DATA

| | |
|---|---|
| • Initial Capital Cost | $171,290,000 |
| • Annual Operating Cost | $ 17,885,000 |
| • Load Factor | 90% |
| • Efficiency | 57% |

Figure 1. An example of a technology module.

A variety of technology modules were developed which fall into the following five groupings:

1. Underground mining—modules varying by seam thickness.
2. Surface mining—modules varying by size of mine and method of mining (area mining and contour mining) as well as by region of the country (Eastern, Interior Province, Western) and type of coal mined (bituminous, subbituminous, lignite).
3. Chemical refining of coal—modules varying by process (aqueous leaching, hydrothermal processing, solvent refining) and by type of coal processed.
4. Coal liquefaction—modules varying by process (H-Coal, CONSOL, etc.) and by type of coal processed.
5. Power plants—modules varying by general type (power plants producing electricity as primary output, power plants producing process heat and/or steam as primary output), varying by application (base load, midrange, or peaking), and by type of coal or fuel form (coal as a solid, coal as a liquid, residual, crude, distillate, or turbine fuel, etc.).

With an inventory of technology modules, it is possible to arrange series of compatible modules to represent the means by which energy, based upon coal, can be delivered to a "common point," and the overall costs of such energy delivery systems can then be computed. The total cost of delivered energy is thus a function of the costs and efficiencies associated with the component technology modules. Figure 2 shows an energy delivery system based upon gasification of coal.

With the exception of the costs of transportation of energy[1], all costs were developed from data produced by the technical studies of the Battelle Energy Program.

It should be noted that the term "cost" as used in this context is intended to reflect all the normal costs required to operate the particular energy delivery system plus a reasonable profit sufficient to maintain an ongoing industry. This cost is to be differentiated from the actual "price" that may be paid by the purchaser. That price can differ widely from cost because of the competitive situation that may exist at a particular time and place.

*Description of the Cost Model*

With the definitions and concepts outlined above, a computerized cost model was formulated. This model provides a consistent framework for the evaluation of energy system costs and efficiency. The primary output of the model is the cost of delivering, from a specified energy delivery system, 1 million Btu of energy in a specified form.

*Model Inputs*

As noted above, the primary inputs to the cost model consist of the cost data and operating efficiencies of each technology module based on 1973 costs. Because of a difference in the cost calculations, the model distinguishes between two types of modules: (1) those that require new investment for implementation and (2)

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[1] Unit train transportation of coal, pipeline transportation of high-, intermediate-, or low-Btu gas, and transmission of electric power.

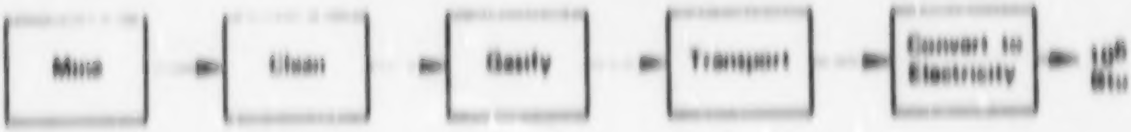


Figure 2. An example of an energy delivery system.

those that require no new investment for implementation. An example of a module of the first type is a high-Btu coal gasification plant, while a module of the second type might be an existing pipeline for shipping the gas.

For modules requiring no new investment, the cost consists of an operating charge and a capital charge. The capital charge includes depreciation, interest, corporate income taxes, and profit sufficient to maintain an industry in a viable condition. All cost figures are expressed in dollars per million Btu of energy output for a given module. In modules that require new investments, the capital charge is computed from the initial investment, the expected life of a new facility, and a specified cost of capital. In the capital charge computation, an annual cost stream is calculated which, when discounted over the life of the facility, equals the initial investment.

The operating efficiency of each module is the second primary input. This information must be provided for all modules. Efficiency for the purpose of this model is defined as the ratio of the Btu output from the module to the Btu input to the module. This definition of efficiency is applicable to all phases of the energy delivery system. In the case of transportation, the energy required to perform the transportation is *not* included.

*Transportation Modules.* In the evaluation of energy delivery systems, three transportation modules were utilized:

1. rail transportation of coal,
2. transmission of electrical energy by 500 kV power lines, and
3. pipeline transmission of natural and synthetic gas.

Rail transportation costs are based upon the equation:

$$\begin{aligned} TC &= 0.5561 + 0.380 \times 10^{-1} D \\ &\quad - 0.266 \times 10^{-4} D^2 \\ &\quad + 1.542 \times 10^{-7} D^3 \end{aligned}$$

where

TC = transportation cost in \$/ton
D = distance in miles.

The equation is based upon freight tariff data compiled by the Peabody Coal Corporation. Based upon cost data for 1971, 73 percent of total cost was assigned to operating costs and 27 percent to capital charges.

Costs from gas pipeline transmission are taken from H. C. Hottel and J. B. Howard (ref. 1). Specifically, a transportation cost of 1.75 cents/million Btu per 100 miles was used. Of this total cost, 22 percent was assigned to operating cost and 78 percent to capital charges. The cost of transmitting electrical energy was obtained from Battelle data. The total cost of 12.3 cents/million Btu per 100 miles is slightly higher than the corresponding cost given in Hottel and Howard. Of the total cost, 44.5 percent was assigned to operating cost and the remainder to capital costs. An overall efficiency of 98 percent was used for electrical transmission lines and 100 percent for pipeline and rail transportation.

*Computational Scheme*

From the above information, a total system cost is computed. This is accomplished as follows. Let there be n modules in a system and let $C_i$ and $E_i$ denote the cost and the efficiency of the $i^{th}$ module. The cost incurred in the $(n-1)^{st}$ module is $C_{n-1}/E_n$, since $1/E_n$ million Btu of output at stage $n-1$ is required to produce 1 million Btu of final output. The total system cost is thus obtained by summing the cost contributions of each module, so that

$$C = \sum_{i=1}^{n} \frac{C_i}{\prod_{j=i+1}^{n} E_j}$$

where

C = total system cost expressed in dollars per million Btu
$C_i$ = cost of the $i^{th}$ module expressed in dollars per million Btu
$E_i$ = efficiency of the $i^{th}$ module
n = number of modules in the energy delivery system

*Cost-Influence Coefficients.* A cost-influence coefficient can be defined for each module in an energy delivery system. The cost-influence coefficient for the i^th^ module represents the change in total cost produced by unit change in the i^th^ module cost. For example if the cost-influence coefficient for the unit train transportation module is 3.0, an increase of 1 cent in the module cost will produce a 3-cent increase in the system cost.

The cost-influence coefficient may also be interpreted as the amount of energy output (expressed in million Btu) required by a given module to produce 1 million Btu of delivered energy. Thus in the unit train example, 3 million Btu have to be transported to produce 1 million Btu of delivered energy. It should be noted that the reciprocal of the cost-influence coefficient of the first module yields the overall system efficiency.

*Efficiency-Influence Coefficient.* The efficiency-influence coefficient quantifies the sensitivity of the total system cost to changes in the module efficiencies. Thus the influence coefficient for the i^th^ module yields the effect of a 1 percentage point change in module efficiency on the total system cost. The influence coefficient is always negative since an increase in the efficiency produces a decrease in the system cost.

In using the influence coefficients described above, it should be remembered that only one parameter is varied at one time. In the case of the cost-influence coefficient, all module efficiencies are assumed to remain at the levels used for the coefficient calculations. For the efficiency-influence coefficients, all cost and efficiencies other than the module efficiency whose effect is to be tested are assumed to remain constant.

## APPLICATION OF COST MODEL

Through internal studies at Battelle, a number of energy delivery systems were defined which utilized a 1,000-MWe power plant and some means of sulfur oxide control. The most optimal systems investigated are described below in table 1.

Basically, the systems compare the utilization of central high-sulfur coal with stack gas cleanup to low- and high-Btu coal gasification, coal liquefaction, and Western coal. Specifically, the prominent features of the systems include:

1. Minemouth—the coal is burned at the mine, and electricity is transmitted 250 miles to the demand center.
2. Western—strip mined low-sulfur coal is shipped 1,140 miles by unit train to the demand center, where it is converted to electricity.
3. Low-Btu—a moving bed dry ash gasifier converts the coal to a clean gas which is piped 250 miles to the demand center. The power plant must be converted to burn the low-Btu gas.

Table 1. Optimal energy delivery systems

| Identifier | Processes | | | | |
|---|---|---|---|---|---|
| Minemouth | Central high-sulfur coal | Coal preparation | Combustion 1,000 MWe | Stack gas cleanup | Electrical transmission 1,140 miles |
| Western | Western low-sulfur coal | Coal preparation | Unit train 1,140 miles | Combustion 1,000 MWe | |
| Low-Btu | Central high-sulfur coal | Coal preparation | Moving bed dry-ash gasifier | Pipeline transmission 1,140 miles | Combustion (retrofit) |
| High-Btu | Central high-sulfur coal | Coal preparation | Hydrane gasifier | Pipeline transmission 1,140 miles | Combustion combined cycle |
| H-C combined cycle | Central high-sulfur coal | Coal preparation | Unit train 250 miles | H-coal process | Combustion future C-C |
| H-C | Central high-sulfur coal | Coal preparation | Unit train 250 miles | H-coal process | Combustion 1,000 MWe |

4. High-Btu—a Hydrane gasifier converts coal to a fuel acceptable for use by current combustion equipment. A pipeline ships the gas to a combined-cycle power plant at the demand center.
5. H-C—the coal is shipped by unit train to an H-Coal thermal coal processor. The resultant clean fuel is burned at the demand center.
6. H-C Combined Cycle—the coal is shipped by unit train liquefaction process. The resultant clean fuel is burned at the demand center in an advance combined-cycle power plant.

The elements described above were combined together with the previously described costing methodology. The resultant cost and efficiency of each delivery system are portrayed in figure 3.

In figure 3, it is seen that the Western coal system is the most efficient and least expensive. This is due to the relative simplicity of the entire system, and the fact that Western coal is strip mined, and thus is less expensive than the deep-mined central coal. The principal reason that the combined cycle H-C system is cheaper than the other H-C system is that the efficiency of the H-C combined-cycle system is higher, thus decreasing fuel costs.

This can be seen more clearly in figure 4, which displays the contribution of each module to total system efficiency. It is clearly evident from this figure that combustion processes are the largest contributor to system inefficiencies, while coal liquefaction or gasification also have large contributions.

The coal processing elements within these systems have each been touted as a means of converting coal into an acceptable fuel at a low cost. However, the actual cost of using these elements is inflated by system inefficiencies. Figure 5 demonstrates the actual, in-place module costs for the various systems. It is seen that the coal processing elements contribute significant costs to the total system costs.

The effect of component cost and efficiency upon total system cost has been clearly delineated in figures 4 and 5. It is seen that the coal processing modules have a

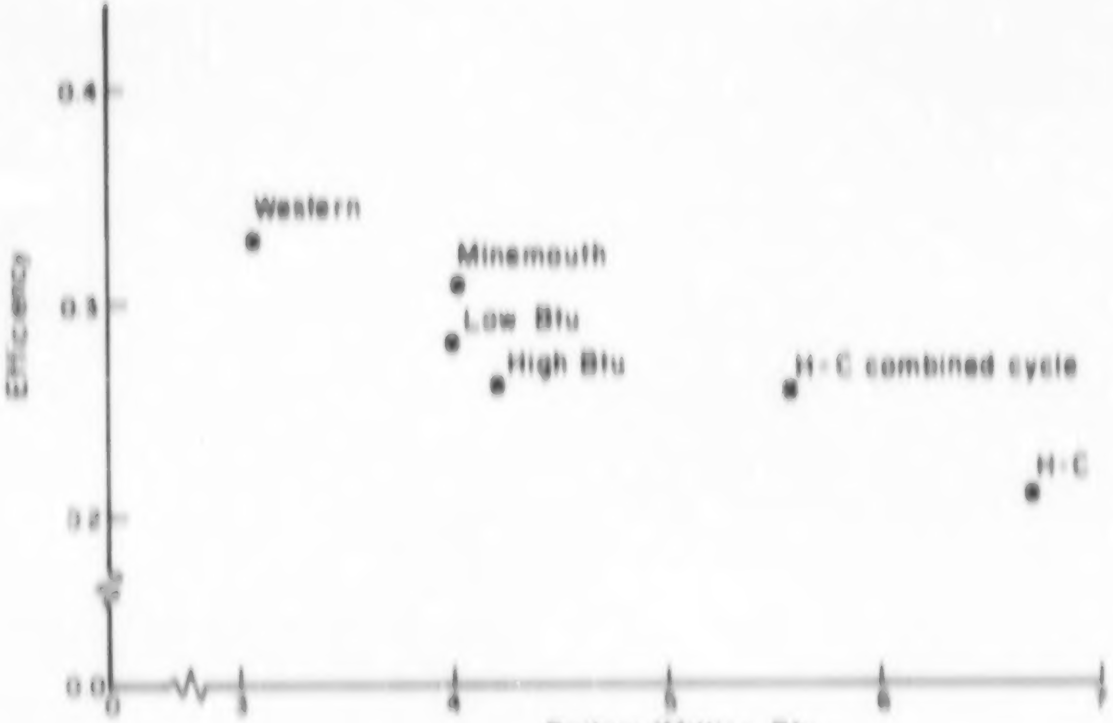


Figure 3. System efficiency versus cost for six systems.

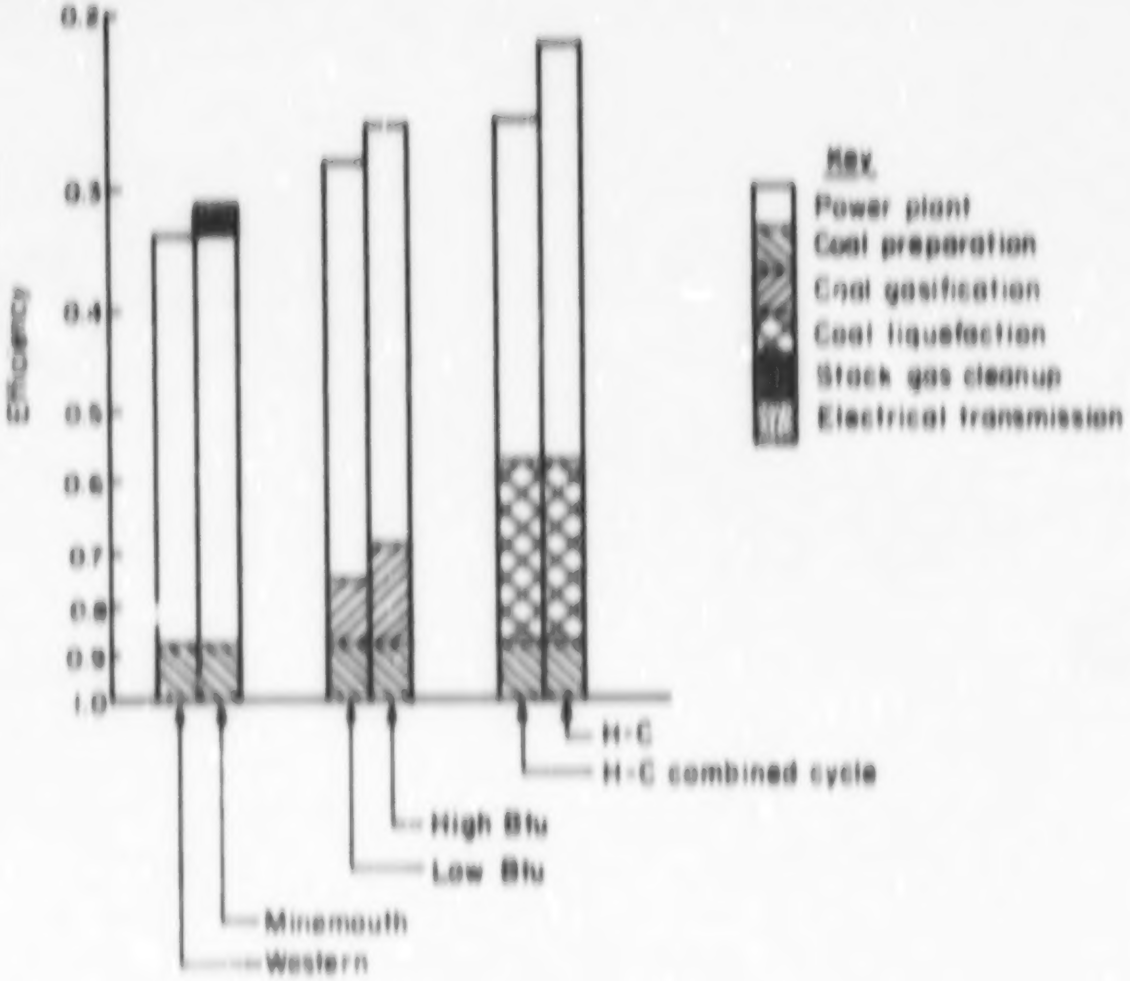


Figure 4. Contributions of system components to system inefficiency.

large effect on both the system cost and efficiency. If these processing techniques are to be a competitive alternative to Western coal, then their efficiencies must be increased and/or their costs decreased.

To examine this further, the cost and efficiency influence coefficients defined earlier can be combined to yield the slope of a component efficiency versus cost curve for which total system cost would remain unchanged. In fact, an analytical curve can be developed which defines the whole curve.

Two such curves are presented in figure 6. This figure illustrates lines of constant system cost for the coal preparation and combustion modules of the energy delivery system for Western coal.

Curves representing the actual cost of combustion and coal processing modules can be imagined superimposed on figure 6. These curves would be concave downward. Their intersections with the appropriate constant cost curves yield maximal efficiencies for identical system costs. As a result, a constant-cost curve which is relatively level has a higher maximal efficiency than a steeper constant cost curve. This feature is a result of the relative importance of fuel cost, and hence the unimportance of other costs, in inefficient systems.

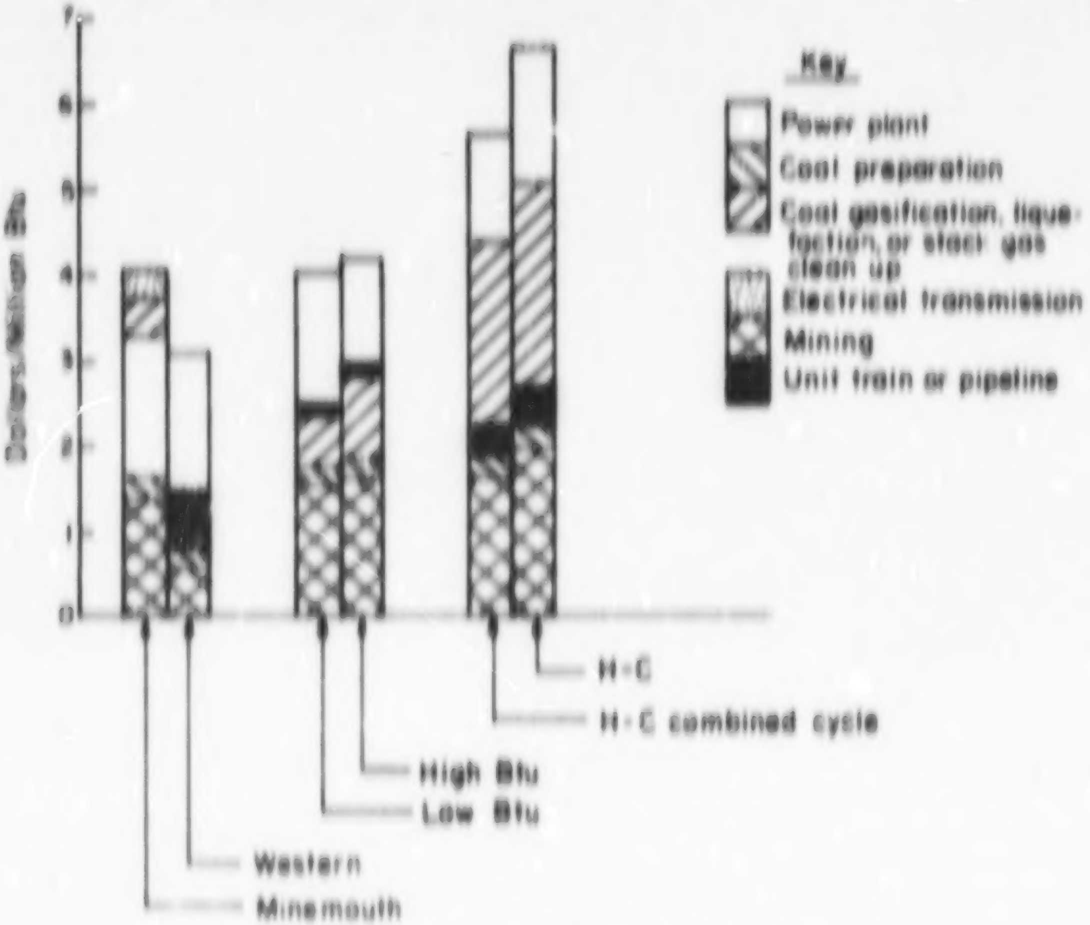


Figure 6. Contributions of system components to system cost.

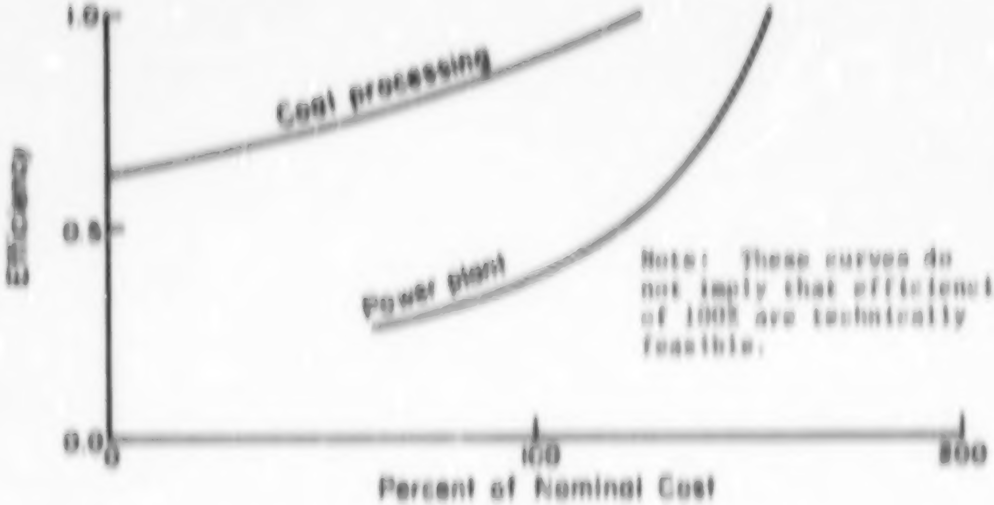
Figure 7 demonstrates the constant cost curves for all of the combustion modules examined. These curves are roughly arranged by order of system efficiency. The most striking feature of this figure is the relative cost which can be incurred by the high-Btu system in order to improve the efficiency of the total system. Conversely, it would appear that increasing the efficiency of Minemouth and Western coal-burning modules could only result in an increased system cost (a fact which is borne out by the lowered efficiencies of modern power plants).

A similar set of curves is presented in figure 8 for the coal processing modules representing liquefaction and gasification. Here, both the gasification modules display a relative cost insensitivity. However, here the gain in efficiency to be achieved is minimal, as the gasification processes are relatively efficient.

## CONCLUSIONS

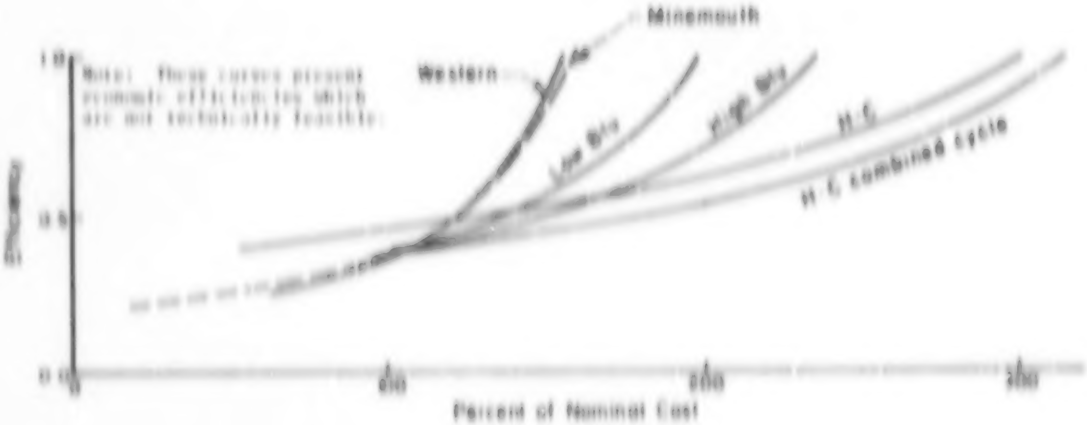
A systematic methodology for evaluating the cost and inefficiency contributions of energy delivery system components was developed and applied to six promising systems for the conversion of coal to electricity designed to minimize sulfur oxide emissions. The results of the analysis demonstrated that:

1. The cost and inefficiency contributions of coal processing modules are multiplied by other system inefficiencies, and thus have a significant effect on total system cost and efficiency.



Note: These curves do not imply that efficiencies of 100% are technically feasible.

Figure 6. Constant cost curves for coal processing and power plant modules.



Note: These curves present economic efficiencies which are not technically feasible.

Figure 7. Constant cost curves for combustion modules.

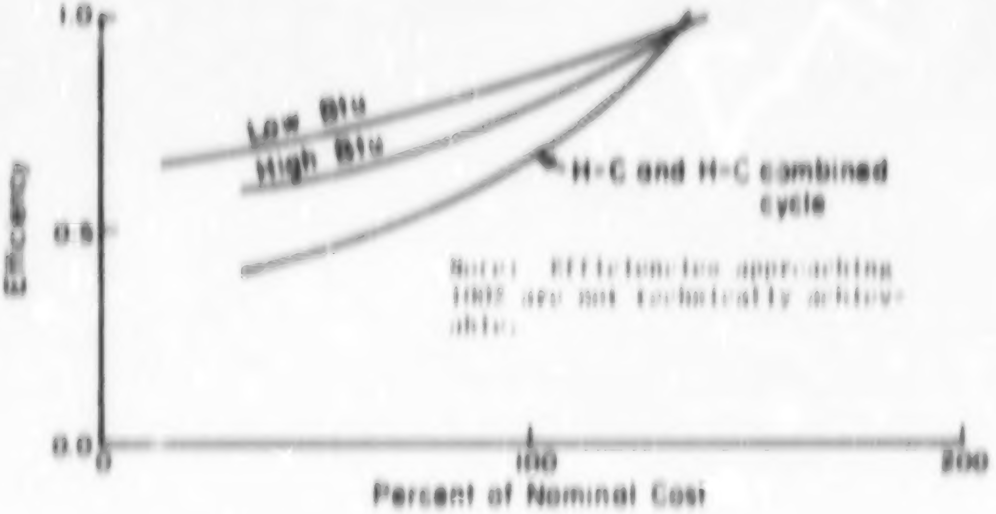


Figure 8. Constant cost curves for coal treatment modules.

2. In opposition to current design, the combustion facilities for liquefied coal could be designed for higher efficiencies with no increase in total delivered cost. The resulting increase in efficiency would greatly affect total system efficiency.

Furthermore, it should be pointed out that the superiority of the Western coal system, both in cost and efficiency, is indicative of an increasing pressure for development of strip mining of Western coal.

## REFERENCE

1. *New Energy Technology – Some Facts and Assessments*, The MIT Press, Cambridge, Massachusetts, 1971.

# ERDA's CONSERVATION OBJECTIVES IN THE TRANSPORTATION SECTOR

John J. Brogan[1]

## *Abstract*

*My presentation is intended to provide an overview of the kinds of activities that we in ERDA have planned for the Transportation Sector and to explain specifically what we are doing now in order to meet two major energy conservation objectives.*

## ENERGY CONSUMPTION IN THE SECTOR

I would like to begin by bringing out some facts related to this energy consuming sector, thereby placing its problems in proper perspective. The Transportation Sector consumes about one-fourth of the total energy consumed by all sectors in the United States. The energy consuming elements of the sector can be divided conveniently into two categories: the nonhighway transport modes, such as air, water, pipeline, etc., which consume about 25 percent of the total energy consumed by the sector, and the surface land transport or the highway mode, covering autos, buses, and trucks. This highway mode consumes about three-fourths of the total energy of the sector, with the auto alone consuming half of the total of the sector.

This sector epitomizes the United States as a whole when it comes to its reliance on selected energy sources. Consider the fact that transportation is almost totally dependent upon an energy source that is one of the least abundant domestically produced sources in this country. Transportation is currently 96 percent dependent on petroleum as its energy source. This sector and the manufacturing directly related to transportation were the most visible casualties of the Arab oil embargo. The impacts of the embargo have lingered with the auto industry especially. Further, when we look closely at this sector, we find that it is almost totally dependent on liquid fuels. Powdered coal is not practical for current auto powerplants. So transportation is a relatively big consumer of energy from perhaps our most critical energy source. It is compatible primarily with liquid fuels, and we do not see early replacement for currently used gasoline. Putting these facts together could lead us to the conclusion that the sector is in potential trouble and that serious consequences are likely if the traditional 'business as usual' attitude continues to prevail in this country. I believe this to be a correct view of the current situation.

## THE ERDA ROLE

Now, just what does ERDA have in mind in attempting to solve these problems?

I believe it is wise to start off by explaining what we see as our role. Our transportation function is part of the Office of Conservation. As such, we see our role as that of providing technical leadership for energy motivated research in all modes of transportation. Our work will span the full range of transport modes, from highway systems to air, water, rail, pipeline, and other cargo and people movers.

The types of activities included will range from studies and technical development to hardware development. We will conduct social, economic, environmental, and energy impact assessments. We will conduct studies that focus on the factors, which influence acceptance and commercialization of different operational-procedure changes and of new technologies. We will conduct critical assessments of institutional barriers that render achieving energy consumption reductions in this sector. We plan to evaluate and, where warranted, develop new transportation concepts. We intend to develop technology from the research phase through to advanced development (these being DOD definitions here), and we plan to develop not only technologies but to build the prototype hardware necessary to demonstrate adequately the technologies to the public.

I recognize that there are some individuals who would prefer that we in ERDA keep a low profile when it comes to carrying out hardware development, that we should concentrate on carrying out only long-term basic research in materials, combustion, etc., and that it should be left to industry to pick and choose any technologies to be developed further. We do not see this as a viable approach under today's conditions. Rather, we have embarked on an aggressive program in developing big technologies in partnership with industry, and we fully intend to pursue with industry hardware development and system demonstration, if the particular work is cost-effective and if it offers the potential of early commercialization.

Finally, at the present time we see the conservation role in transportation as end-use oriented, because we believe that the biggest payoff is there. Also, other organizational elements within the Office of Conservation are hard at work on reducing consumption in industrial processes associated with manufacturing in industry. In addition, at present other organizational elements within ERDA are hard at work reducing energy waste in producing synthetic liquid fuels from fossil energy sources which someday may appear as the primary energy source for the sector.

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[1] Acting Director, Division of Transportation, Energy Conservation, Energy Research and Development Administration, Washington, D.C.

We recognize that this perception of conservation in transportation could change in the future. Our concern here is that proposed changes made in the transportation system eventually have to be traced back to their net energy savings, and under certain circumstances the end-use consumption could be reduced. But to accomplish this the net change could be an increase. This comes right back to the pervasiveness of conservation, and it will take time to better understand the nature of conservation.

## PROGRAM OBJECTIVE

The Transportation Program focuses on both near- and midterm, with midterm covering 1985 to 2000. There are two major objectives in the program, and each can be traced back to the alarming facts cited earlier regarding energy consumption by the sector. These objectives are: (1) to reduce energy consumption in the earliest possible time consistent with environmental constraints, and (2) to develop, demonstrate, and promote commercialization of operational procedures and technologies that will eliminate the dependence of the Transportation Sector on petroleum energy.

While we would like to make the major impact of the program felt before 1985, we foresee our biggest potential opportunities coming after that date. This means that we must be astute enough to work at the same time on achieving both objectives.

## ACHIEVING THE OBJECTIVES

Achievement of the first objective suggests that ERDA consider known, but either unused or partially used, operational improvements and technologies, as well as developing new ones. In the area of known technologies, etc., we recognize that we may be plowing ground that has been plowed before by other agencies. In this event, we propose to join forces. In promoting commercialization of either known or new technologies, we also propose to join forces with other government agencies. The point that I make here is that the ERDA conservation function in transportation intends to become involved, whether it be with known technology or new technology development.

When it comes to near-term impact, we are concerned about the 110 million autos on the road today. A relatively small 1 mpg increase in average fuel energy could result in 300,000 barrels-per-day reduction in imported oil. This enormous leverage potential lies primarily in the auto and secondarily in the long-haul truck segment of the sector. We want to understand why past attempts failed to convince the public that scheduled tune-ups save the public money. We want to know whether it would make good sense for the government to pay a partial cost for a tune-up. We may be surprised when we look at the areas. We want to know what previously known and proven traffic-light control techniques to improve traffic flow are practiced in few cities in this country. We want to know why previously known and proven aerodynamic drag-reduction devices on trucks are not being used by truck owners. We want to respond to many of the old idea files that have been discarded for years because perhaps the economics of their implementation simply were not right when conceived. We feel that we can serve a useful role as a catalyst in this area, and we are letting the public, universities, and industry, large and small, know that we are interested in their suggestions for ways to reduce energy consumption in this sector.

The two program objectives are compatible. As we see it, the reductions in consumption will appear in gradual changes at first in fuel-consumption data, unless another embargo hits us or unless government regulatory forces appear. The introduction of new and energy-efficient powerplants, such as the gas turbine and Sterling cycle systems, if successfully developed by 1980, could have a pronounced impact in consumption in the sector. Work is underway on these developments. The multifuel capability and very low exhaust emissions make these systems especially attractive. Introduction of the battery-powered electric vehicle is another event that we are working toward at this time, with increased emphasis on system and component developments, especially the battery. The use of nonpetroleum-base fuels in the sector appears high in our program priorities. Particular emphasis is being placed on methanol from coal and on synthetic gasoline and distillate from coal and shale. Hydrogen as a candidate fuel in the sector is also being pursued.

While I have discussed mainly highway vehicles because they consume three-fourths of the total sector energy, we are proceeding to firm up our plans for meeting with program objectives for the other transport modes. We recognize that in some cases other agencies have been established in research roles. We are currently putting together data on all of the ongoing work in air, rail, etc., and are carefully reviewing directions and objectives of this work to determine whether further opportunities exist for reductions in energy consumptions. At a minimum, ERDA intends to keep abreast of all ongoing energy related work in each transport mode, even where ERDA research funds are not being used.

I believe that covers an overview of ERDA's Transportation program. I point out that conservation is new to us here in the United States. I am not aware of any conservation energy experts in the transportation field, mainly because virtually none of us in the past have had the chance to practice being an expert in this area.

3 November 1975

### Session II:

## NONTECHNOLOGICAL METHODS TO CONSERVE ENERGY

David R. Berg[1]
Session Chairman

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[1] Acting Director, Environmental Technology Assessment Branch, Office of Energy, Minerals, and Industry, Washington, D.C.

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# ENVIRONMENTAL IMPLICATIONS OF NONTECHNOLOGICAL METHODS TO CONSERVE ENERGY

John H. Gibbons[1]

## Abstract

*U.S. policy to improve health, safety, and environment has resulted in higher energy prices, reflecting more adequately its true cost. The OPEC cartel price shift raised prices further. In response to higher prices, energy users are shifting to less energy-intensive consumption patterns and higher efficiency of use. The environmental implications of these altered consumption patterns are generally salubrious, because the actions taken to save energy are much less polluting than using the energy. Most other policies to induce additional conservation will not only save consumer's money but will further reduce environmental insults. There are some proposed actions to save energy by relaxing environmental controls. While a small amount of energy could be saved in this way, it seems far more productive to save energy through increased efficiency of use rather than a retreat from environmental goals.*

It is very difficult for a technologist, such as myself, to constrain his remarks to a discussion of "nontechnological methods." Since that is my assignment, however, I will do my best to stay on the subject with only two caveats: (1) I assume that it is legitimate to discuss actions which may be technological but do not require the development of new technology. (2) I remind you that most policy decisions about resources (including energy) engender technological responses because technology is one of our most powerful means to respond productively to socioeconomic perturbations.

Sometimes the best way to understand the present condition and to anticipate the future is to examine the past. On the other hand, the famed Satchel Page cautioned us in discussing his philosophy of his life to "... never look back: something might be gaining on you...."

U.S. energy policy prior to the emergence of the environmental movement in the 1960's was relatively simple and straightforward. It consisted of a technological policy to develop nuclear energy and a nontechnological policy to (1) maintain minimum price for energy resources and (2) provide maximum availability of energy resources. The doctrine of minimum price was achieved at the expense of several very important things:

1. *Environment and Health.* Throughout the domestic scene, major environmental pollution and human health costs were allowed to be unfairly borne by air, water, land, and people. These "environmental externalities" amounted to nonmarket costs of energy production which were not associated with the same places or people where the benefits of low-priced energy were enjoyed. For example, we now pay out of general tax revenue about 1 billion dollars per year in black lung benefits and will continue to pay similar bills for many years to come. These very real costs of underground coal mining were not included in the price of the coal so obtained in past years. Thus, the benefits of "cheap" coal were enjoyed by one generation but the costs were levied on the next generation.

2. *Domestic energy resources.* The policy of maximum use of energy resources through a variety of schemes to subsidize its price caused energy resource extraction to be accelerated to a rate that simply cannot be maintained for more than a few decades. At the present time, fossil fuel consumption of oil and gas amounts annually to the equivalent of at least a hundred thousand years of production. Domestic natural gas supplies, despite the major finds in Alaska, have already peaked out; oil production is peaking at the present time and the costs of incremental additions to oil and gas reserves are exponentiating rapidly.

3. *Domestic energy resource independence.* The very high growth rate of demand began to overwhelm domestic production capability of oil in the early 1960's. Rather than alter our energy consumption policies or patterns, we turned to imports as a means to continue the "energy feast." This amounted to a willful relinquishment of national independence; the real cost did not occur to us until 1973.

The collective impact of these nontechnological energy policies was a de facto subsidy of energy prices, which caused demand growth rate to rise from a little over 3 percent in the 1950's to nearly 5 percent in the early 1970's, despite the fact that the thermal efficiency of power plants and the energy efficiency of railroad locomotives increased sharply from 1950 to 1970. Energy efficiency in the consumption infrastructure (e.g., automobile mileage) fell steadily.

*The advent of the environmental movement in the latter half of the 1960's can now be seen as the first major step in altering our energy policy,* even though it was not viewed that way at the time. The environmental

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[1] Director, Environment Center, University of Tennessee, Knoxville, Tennessee.

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movement arose in part from the explosive growth of energy demand and accompanying pollution problems that resulted not only from cheap prices but also from spreading population and the growth of affluence known as the "throw-away society." The environmental movement also was precipitated by regional environmental overload caused by the implosion of human activities (e.g., increasing unit size in power plants, increasing urbanization).

Environmental legislation such as the clean air and water acts, the National Environmental Policy Act, the Coal Mine Health and Safety Act, the Occupational Safety and Health Act, and others reflected a realization of major external costs in our economy, unfairly born by society, and a national decision to internalize these costs. In effect, we moved from a "pay tomorrow" philosophy to a "pay as you go" philosophy. The rationale is well illustrated by a tale from "Peanuts." Lucy exclaims to Linus, "This generation has been given the works! All the world's problems are being shoved at us." Linus responds, "Well, what do you think we should do about it?" Lucy: "... we'll stick the *next generation*!" It is not hard to see that we *have* been sticking the next generation for many generations. It is heartening to see that we are beginning to change that pattern. The environmental legislation impacted energy production and use especially hard because that is where most of the environmental problems were located.

The impacts of the environmental/energy policy decisions were many. In addition to direct impacts on air and water quality, there were at least two important consequences in the area of energy:

1. *Energy prices increased significantly.* We should recall that the actual total cost of energy did not change, but rather the external environmental costs of energy production and use were reallocated to the consumers of energy. The consequence of this impact was the initiation of a move on the part of energy consumers toward greater efficiency of energy use.

2. *The minimal environmental impacts of natural gas production and use were such that users of other forms of energy began to turn to natural gas.* As a consequence the demand for natural gas, already high because its price had been held artificially low through price controls, accelerated to even greater heights. Our national store of natural gas now dwindled in the wake of explosive demand growth, and the ratio of gas reserves to annual demand fell steadily. The consequence of this response was that we enjoyed a rapid move toward improved environmental quality, but only by borrowing from the future.

The second major event in our changing national energy policy did not arise indigenously like the environmental movement, but rather was externally imposed upon us. This was the oil embargo placed on shipments to the United States by the Arab states in the Arab-Israeli conflict of 1973-74. In retrospect that traumatic event was important and productive shock therapy for the Nation. Adlai Stevenson once observed that "man does not seem to see the handwriting on the wall until his back is up against it." The handwriting on the wall about the hidden costs of becoming dependent on foreign oil was made very clear through the embargo. It drove home a realization of the finiteness of oil and gas resources and also the extent of our growing dependence on nondomestic supplies. Perhaps more importantly for the short run, it gave a real specter of the uncertainty of availability of energy and triggered a rapid consumer shift in purchase decisions, particularly in the area of automobiles. The embargo crystallized a national consensus about the need to develop domestic energy resources and the imperative to improve the efficiency with which we use energy in the United States.

The myth that greater energy consumption, per se, necessarily implies greater productivity and economic progress was beginning to tarnish; so too was the myth that it is not practical to save a significant amount of energy.

The third major event in our new national energy policy, again imposed by external forces, was the OPEC cartel price shift and subsequent ripple of higher prices for other energy resources. We are in the process of responding to this era of higher energy price, and so it is difficult at this time to anticipate exactly what the total response will be. Nevertheless, several things are quite clear. Energy prices have become largely uncoupled from current production cost. Rather than reflecting average cost, prices now more closely reflect the incremental cost of bringing in new energy supplies (e.g., oil from under deep water off the eastern coast of the United States). The higher price level (which is currently our most basic energy conservation strategy) was a gift from the OPEC countries and should be viewed as a very important assist, albeit traumatic, to the United States in adopting a more enlightened energy policy. The implications of the new era of higher price are many and diverse:

1. Our energy supply system, primarily oil, gas and coal, now has the opportunity to become more diverse through the addition of other energy sources heretofore uneconomic (e.g., geothermal). As the relative price of energy increases, the type and number of "new" energy sources that become economically attractive increases sharply. The fastest way to discourage investment in a more diversified energy supply system would be to roll back present prices to previous levels of

even to hint that this *might* be done as a matter of national policy!

2. The new energy price immediately makes it economically attractive to alter the energy consumption infrastructure to one of much higher efficiency. This can be effected through direct substitution (e.g., better insulation instead of bigger furnaces and air conditioners), increased efficiency of conversion (e.g., more efficient air conditioners and automobiles), and minor modifications in lifestyle (e.g., set back thermostats at night, returnable beverage containers, more careful automobile trip planning). In almost every instance, these kinds of moves toward increased efficiency imply an *increase* in domestic economic activity and improved environmental quality, contrary to the rumors and myths which proclaim such moves would surely deflate the economy.

3. The new price level means that it is now important to reevaluate the benefit/cost of various public policies that were created during an era of cheapening energy price. (In the public sector this includes such policies as freight rules, depletion allowance, power plant cooling tower requirements, etc.) I do not want to imply that I feel that all of these policies should be changed; energy price may have very little to do with their basic validity. However, if public policy like environmental control is based on benefit/cost calculus, then the associated policies should be reexamined whenever significant changes occur in either the benefit or cost parameters.

4. Several years ago the price of coal was such that the environmental externalities were a significant fraction of its market price (e.g., coal price at 7 dollars per ton, environmental externalities estimated to be 3 dollars per ton). Now that the price of coal has risen in proportion to the new oil price, the cost of reclamation and of other externalities becomes a very much smaller fraction of total coal price and should therefore enable decisions to internalize the external costs to be much more palatable.

From an environmental point of view, the points we make in the preceding paragraph bring both good news and bad news. First the good news: the substitution of materials, time, labor, and human ingenuity for energy—simply because it's cheaper that way—is very salubrious in terms of the environment and is also an economic imperative. Likewise, the shift away from dependence on fossil energy resources toward a time when we learn how to meet our energy needs with sunlight and possibly fusion is undergoing rapid acceleration, and none too soon because it may take us a half century or more! At the same time there is bad news beyond the near term economic dislocations caused by such a sudden change of events. Perhaps the greatest area of concern is the implied massive shift toward increased coal production and combustion in response to the change in price and lessened assurance of availability of oil and gas. If we use present technologies for mining, conversion, and combustion of coal, the environmental implications seem little short of disastrous.

Realistically, however, there seems to be little incentive for users to shift from oil to coal because the relative price difference between these two energy commodities is not all that great. Furthermore, the chance for the international oil cartel price to be undercut during the next several years is small but finite. When one couples that fact with the uncertainty about the long range U.S. public policy on energy, one can only surmise that private investors will be very reluctant to commit the very large amount of capital investment required to significantly expand U.S. coal production in the near term. It is possible that for a number of years we may have much more oil available to us than coal.

Finally, we should remember that, while the "market place" has a great deal of appeal in terms of the allocation of goods and services, it cannot be automatically depended upon to allocate costs and benefits in equitable fashion. One needs only a cursory glance at the coal fields of Appalachia to understand the dramatic reality of existing socially uneven impacts of costs and benefits of domestic energy production.

Now that we have reviewed the environmental implications of energy policy developments that have occurred over the past several years, it seems appropriate to consider several *future* policy options and their implications on environmental quality.

1. *Rollback prices.* Some members of the Congress opt strongly for this approach, especially for oil price. To be sure a cut in oil price would be a welcome palliative for the short run, but I maintain that it would be disastrous in the more important long run. First, it would deter if not reverse the present move toward more efficient use of energy in the United States. Secondly, it would exacerbate the problem of decreasing production of domestic gas and oil. Third, it would deter severely the investment and interest of American industry to diversify our energy resource base. In general, therefore, a rollback of energy price or even a hint that this might be seriously considered would probably be the most effective single thing we could do as a nation "to stick the next generation."

2. *Assure a "platform" price for energy; deregulate oil and gas prices.* At least a portion of this policy option is currently being seriously considered by the Congress and the Administration. If such a policy were developed with appropriate time phasing it could induce very productive responses. First, the assurance of future

prices that are level or increasing will induce investments to make our energy consumption more efficient and would also induce lifestyle accommodations that are less energy-intensive. Second, the assurance of future price would undoubtedly precipitate increased investment to expand and diversify domestic energy supplies. To be sure, there would be some hardships, but that situation is not new. In the days when energy was made cheaper by allowing external costs, it was the economically disadvantaged Americans who lived downwind from the smokestack and in the coal fields that bore an unfair portion of energy costs. Today, higher energy prices take their heaviest toll among the middle class and disadvantaged, but we can ill afford to subsidize energy price for all energy customers in the name of "helping the poor."

3. *Public policies to induce shifts to increase efficiency of use.* There are a variety of policies now under consideration which could accelerate the rate and extent to which we become more energy efficient. These range from extremely minor perturbations of the market system to heroic measures such as rationing. We summarize these as follows:

(a) *Labeling, education, exortation.* Using these techniques through Federal, State and local actions, we could provide consumers with better market signals which could enable them to make more energy-conscious decisions. We could retrain architects and engineers to think about energy in the design of new buildings or in their renovation of existing buildings. We could influence industry and the financial community to produce consumer hardgoods and buildings that are designed for minimum total life costs, which generally implies much higher energy efficiency than is the current style. The environmental impact of such actions would be generally very good. People would tend to dress for the season and in general to use less energy intensive lives.

(b) *Minimum performance criteria through regulation and incentives.* As in consumer safety it seems sensible to insist on minimum performance for energy-consuming products consistent with minimal total cost. Therefore, it seems sensible to establish uniform building codes and standards both for new structures and for the renovation of old structures. Similarly, it might make good sense for minimum efficiencies to be established for air conditioners since there are many on the market which sacrifice energy efficiency for a slightly lower purchase price that results in a much higher lifetime operating cost for the consumer. The economic and environmental impacts of such actions are very good in that employment would tend to increase, and less energy would be required to sustain a given standard of living. However, such rules would limit consumer choices and "freedom" of the market place. On the other hand, it can be argued that such minimal performance rules or tax incentives and penalties would provide an inherently more equitable consumer market.

(c) *Allocation and rationing.* Some people feel that equity can only be achieved by establishing policies that bypass the price system. Therefore, the concept of price-induced actions to decrease per capita energy consumption is seen to be regressive compared, for example, to rationing. Such policies, if put into place, would certainly make the *reality* of the energy problem much more convincing, but would create a bureaucratic nightmare of cost and complexity that hardly seems justifiable.

(d) *Relax and alter environmental and other regulations.* Some argue that, in the face of higher energy price and the imperative to become less dependent on foreign energy sources, we should make major changes in existing regulations. Power plant emission controls are accompanied by an energy efficiency penalty of several percent. Automobile emission control carries an energy penalty of up to 15 percent. Energy transportation rules force energy inefficient modes in the transport of people and goods and subsidize the use of energy intensive virgin materials over recycle materials. The environmental impacts of these various policy changes are mixed. In some instances there would be strongly negative impacts but just the reverse in other cases. Even in those cases where environmental impacts seem bad there are some productive possibilities under certain conditions. Consider electric power plants: the increase of conversion efficiency that would result from allowing more direct cooling and less use of cooling towers implies a decrease in the amount of required capital, as well as a decrease in operating expenses. These "saved" dollars *could* be plowed back into the economy in a more productive way, for example in building new medical schools. Alternatively (and, unfortunately, more realistically) the "saved" dollars could be used to reduce electricity prices and consequently accelerate energy demand growth and foster further decreases in efficiency of use!

## CONCLUSIONS

1. The impacts of energy conservation on the environment (including not only pollution and health but also employment and activity levels) are generally very positive but depend very much upon the specific strategies employed. This means that in developing energy conservation policy, like everything else, we should use our brains.

2. Even with full-cost pricing additional incentives for energy conservation are justified because there are

nonmarket, national needs to become more energy efficient beyond the signals that we get from the market place. These additional imperatives for energy conservation include the need to reduce oil imports and the long-term need to conserve fossil energy resources for nonfuel uses. This implies that we need uniform Federal legislation: a surrogate for productive "mutual correction" through the application of collective national wisdom.

There are strong impediments to instituting energy conservation programs. First come the myths about energy conservation, which require time to dispel. Many of these were purposely created by industries trying to sell more energy or energy-consuming items. The Arab embargo helped to reinforce the idea that conservation was equivalent to "tightening the belt" or "freezing in the dark." To the contrary, conservation means "wise use"; it is simply the practice of sensible economic decisionmaking.

Any change in our economic system, particularly that arising from technological innovation, implies some job displacement and sometimes decreased employment. For example, the tractor displaced a lot of farmworkers and horses. It also enabled us to eat better than before. Fluorescent lights closed a lot of incandescent lamp production lines, but enabled Americans to enjoy light less expensively. As we examine the specific strategies for energy conservation through increased efficiency we see, contrary to much popular opinion, that there is some job displacement, but generally greater employment rather than less.

There is also the myth that energy conservation somehow denies the poor their chance for the "good life." It is difficult to see how such an idea makes sense when conservation is designed to *maximize* the extent of goods and services that can be provided by a given amount of resources. I personally believe that it is only through repeated encounter with the specific strategies for energy conservation that we will dispel the counterproductive myths about its undesirability.

Finally, in responding to the energy problem through alteration of demand patterns we encounter perceptual difficulties that arise from the ways we've thought about problem solving ever since the beginning of the industrial revolution. It was through the industrial revolution and the move to the western hemisphere that we achieved so many material gains for mankind. We lived in an infinite world in which riches were to be found by "moving west" and by expanding production. Ours came to be known as the "cowboy economy." In the energy problem we encountered more sharply than ever before the reality of the anachronism of these time-honored ideas. Now the exponential, which until very recently was equated with progress, becomes in many instances a mortal enemy. We take every opportunity to try to avoid thinking seriously about how we might transform ourselves into a society that is in dynamic equilibrium. In the decade of our 200th national birthday, we can no longer escape confrontation with these thoughts. Hopefully we have the capacity and will to make a productive response, and an excellent subject on which to begin is energy!

# FEDERAL INITIATIVES TO SAVE ENERGY IN LIGHTING AND APPLIANCES

Kurt W. Riegel, Ph.D.*

## Abstract

*Energy savings to the Nation and to individual consumers can accrue from the following approaches:*

1. *Research and development on new technologies that will lead to more efficient appliances, lighting systems, and control systems that govern their use.*
2. *Improving the energy efficiency of new appliances and lighting equipment by better incorporating presently available technology.*
3. *Motivating purchasers of appliances and lighting equipment to make selections based on energy efficiency and life cycle cost, thus creating market pressures for more efficient manufactured products.*

*The Federal Government is engaged in programs that follow all of the above approaches. The Energy Research and Development Administration has programs for research, development, and demonstration of energy efficient technology in appliances and lighting. The Federal Energy Administration and the Department of Commerce conduct a Voluntary Appliance Efficiency Improvement Program, the purpose of which is to encourage implementation of presently available technology in new and more energy efficient appliances. The Federal Energy Administration encourages wise use of energy in lighting to conserve energy through two programs: the Federal Energy Management Program and the Lighting and Thermal Operations Program. Both Federal operations and the private sector are the targets of these efforts. Finally, consumer awareness and motivational issues relating to efficient energy utilization are being addressed in such programs as Commerce's Voluntary Appliance Labeling Program, FEA and ERDA research projects, and by legislation calling for stronger programs in all of the mentioned subject areas.*

## INTRODUCTION

I am happy to speak today about current Federal programs for energy conservation in lighting and appliances. This is so particularly because of the close relationship between energy use by lighting and appliances and environmental quality. Thus, the subject seems to be in perfect harmony with the principal subject of this symposium. With exceptions that are rather minor on a national scale, appliances and lighting draw energy for their operation principally in the form of electricity or gas. Both forms of energy play a very important role in the current debates over energy and environmental policy, for quite different reasons. Natural gas is one of the cleanest-burning fossil fuels available for onsite use to operate appliances and major climate conditioning systems. Gas is currently affected by supply and demand factors that are troublesome to large segments of the economy. Some believe that electricity has associated with it some of the most worrisome and difficult environmental problems facing the Nation. Thus we expect that energy conservation programs that reduce or defer the growth of natural gas consumption and electricity usage will make a strongly positive contribution to the preservation of environmental quality and to the development of an orderly national energy policy.

To give some numbers, lighting is virtually entirely electric in this country, except for some decorative types, and presently accounts for about 5 to 6 percent of total national energy consumption, or about 20 to 25 percent of total national electricity production. These figures are made up mostly from direct lighting energy consumption, but also contain a small excess contribution due to indirect demands for energy, particularly in large commercial buildings, for climate conditioning requirements that are driven by internal building lighting loads.

Appliances will be defined here to include water heaters, refrigerators and freezers, ranges, television sets, room air conditioners, clothes dryers and washers, and dishwashers. Excluded from this discussion are major climate conditioning equipment such as central heating and cooling equipment. Small home appliances account for less than 10 percent of all appliances energy consumption. Altogether, residential-type appliances account for about 8 percent of total national energy consumption, a number which is large enough to consider as a part of the total national energy conservation program. Of this, over 70 percent is in the form of electricity, and most of the rest is natural gas. Thus, previous remarks about the importance of electricity apply strongly to appliances.

At this point it will be useful to break the discussion into two separate parts, appliances and lighting. The various Federal programs that operate in these two areas will be described.

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## APPLIANCES

The three Federal agencies with energy conservation activities relating to appliances are the Energy Research and Development Administration (ERDA), the Federal Energy Administration (FEA), and the Department of Commerce through their National Bureau of Standards (NBS). It is apparent that large energy savings can be achieved in three different ways:

1. Research and development on new technologies that will lead to more efficient appliances, lighting systems, and control systems that govern their use.
2. Improving the energy efficiency of new appliances and lighting equipment by better incorporating presently available technology.
3. Motivating purchasers of appliances and lighting equipment to make selections based on energy efficiency and life-cycle cost, thus creating market pressures for more efficient manufactured products.

ERDA, which started its conservation program in July of 1975, is currently working with a FY 1976 budget of approximately $17 million for all of its buildings' energy conservation activities this fiscal year. Of this total, approximately $0.6 million will be obligated for the support of research, development, and demonstration activities in appliances. Included in the RD&D agenda for appliances are projects to develop more fully the data base on actual appliance operation and energy consumption according to appliance technical attributes and according to climatic and other factors that are important. Shortly after the first of the year, we will host a conference on "Technical Opportunities for Improved Appliance Efficiency," which will convene experts to begin the process of developing information on appliances useful to ERDA in setting priorities for support of RD&D in this area, and useful to the appliance industry in stimulating change and innovation with respect to conventional appliances. Furthermore, ERDA intends to explore the potential for developing integrated appliances which combine several conventionally separate appliances to take advantage of waste heat and, thus, reduce energy consumption. There are several cases of appliances that have complementary functions, for which such integration is expected to provide large energy savings; there are promising applications for such integrated appliances. For example, integrated refrigerator-water heater appliances might be introduced in factory-built modular home units, a portion of the industry which is projected to continue to account for a large fraction of new housing. Finally, as a result of ERDA activities, technical opportunities for changes in both residential and commercial appliances will be identified, and RD&D efforts will be supported so as to encourage and stimulate the introduction of energy saving appliances. It is estimated that by 1980, rather minor changes, well within the bounds of existing technology and practice, could result in cost-effectively improved appliances with efficiencies 20 percent greater than the 1972 base case, averaged over all appliances, energy and production weighted. (See appendix A, "Technical Opportunities for Improving the Energy Efficiency of the Nation's Appliances.")

Technical measures for improving the energy efficiency of appliances include, as a sample, insulating water heaters, ranges, and refrigerator/freezers more effectively; replacement of the standing gas pilot lights with intermittent ignition devices in water heaters, ranges, clothes dryers, and other appliances; improvements in heat-exchanger efficiency in refrigerator/freezers, room air conditioners; heat recuperation; and improvements in controls in refrigerator/freezers, room air conditioners, and other appliances. For example, the present day automatic defrost refrigerator goes through its defrost cycle mindlessly on a regular repetitive basis regardless of need; controlling the defrost cycle so that it is actuated only when actually needed would give energy savings.

ERDA, FEA, and NBS are all very interested in motivating purchasers of appliances to consider energy efficiency as an important factor in final selection. NBS has a voluntary appliance labeling program, which provides some energy information in the form of a label affixed to appliances displayed on the showroom floor. For the air conditioner, the information has been EER, energy efficiency ratio, the ratio of heat pumped to electric power input. For other appliances, such as refrigerators and water heaters, the information displayed will be in the form of operating cost. Present information about consumer motivation indicates that annual cost of operation is probably the simplest and most effective way to communicate energy efficiency information to the consumer. From a public policy standpoint, the necessity to communicate effectively with the consumer should be an overriding consideration, since mere technical accuracy unaccompanied by consumer understanding will not effectively influence decisions toward efficient, life-cycle cost-justified appliances. It is taken for granted that the long-term effect of large numbers of individual consumer decisions in favor of efficient appliances is to stimulate the manufacture of appliances with larger industrywide average energy efficiency than without a labeling program.

There is some very interesting and promising legislation pending in the Congress, which is intended to extend the present NBS voluntary program and to result in greater effectiveness with the consumer. The House and

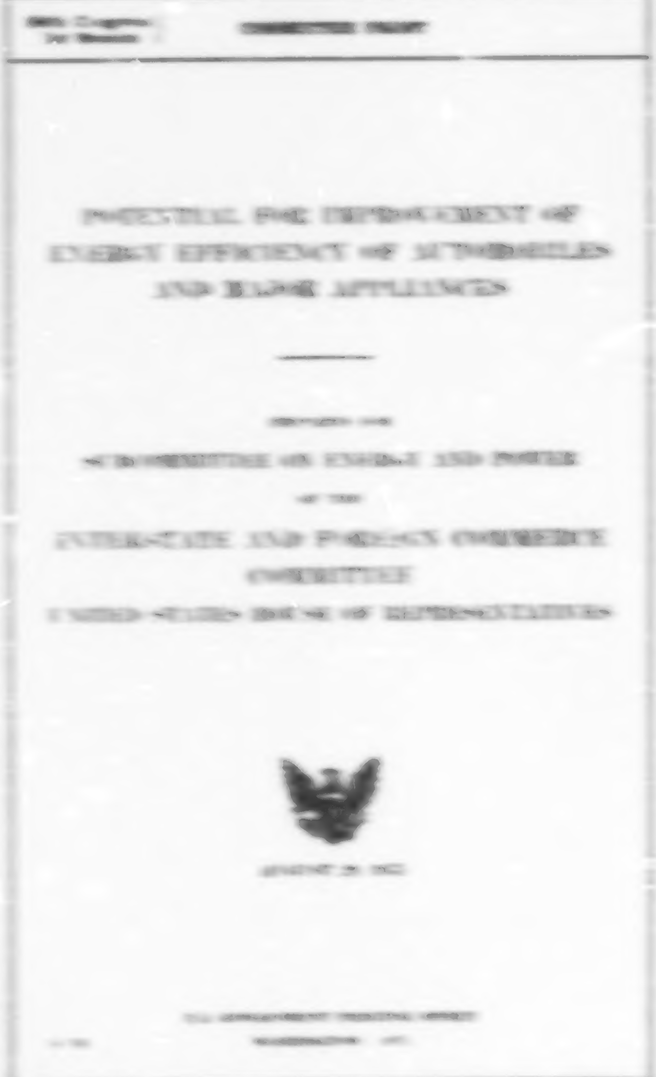
Senate have recently reported out of conference a bill that would require mandatory annual cost-of-operation labeling for the major energy consuming appliances, and would furthermore set an energy-efficiency improvement target of 20 percent for newly manufactured appliances. If the Administrator of FEA determines, after a specified period of time has elapsed, that progress toward attainment of the 20 percent goal is not satisfactory, then a mandatory standards provision of the legislation can be activated. The standards provision is a very useful backup to the labeling and efficiency target provisions, since there is very little information on what progress can reasonably be expected from them alone.

Finally, I should mention that the Department of Commerce and FEA have a program for Voluntary Appliance Efficiency Improvement. Targets have been established, and these two agencies have established a timetable for obtaining a 20 percent improvement in efficiency by 1980. The program was in response to a call for the President in the 1975 State of the Union address for such a voluntary program.

## LIGHTING

There are promising technical approaches that might be taken toward the development and implementation of new lighting technology, both with respect to components (light sources and fixtures) and controls. ERDA will support the RD&D activities leading to more efficient light sources through such projects as one to produce a fluorescent light bulb suitable for replacement of the standard incandescent light bulb. Efficiency improvement of over a factor of three seem technically feasible and would provide the first real innovation that is capable of penetrating the large residential incandescent market. Controls that are inexpensive enough to achieve significant national usage, with respect to time scheduling or available natural light, would also offer energy savings and will be explored by ERDA. Finally, the relation between human visual performance and the visual environment will be investigated in order to provide a more rational and accurate basis for specifying illumination levels and visual design of spaces in buildings; this phase of the program activity is essential to the development of energy performance standards for buildings, a major ERDA activity.

In the days shortly after the oil embargo, the Federal Government moved to take emergency action on its own energy consumption, through a program that is now called the Federal Energy Management Program, at FEA. As a part of the Federal program, the General Services Administration conducted extensive delamping of Federal buildings to meet illumination guidelines referred to as the 50/30/10 standard (50 footcandles on the desk, 30 footcandles in areas surrounding work stations, and 10 footcandles or less in hallways and other noncritical areas). FEA built on this in the Lighting and Thermal Operations program, which continues today. The objective of this program is to take some of the energy conservation measures that have worked best in Federal buildings and encourage their application in the private sector on a completely voluntary basis. A publication entitled "Lighting and Thermal Operations Guidelines" has been made widely available and forms the core of a marketing effort to encourage the adoption of energy conserving lighting and climate conditioning practice. In Federal buildings, energy consumption has been reduced about 18 percent below preembargo levels, mostly as a result of the measures included in this program. FEA also sponsored research on lighting energy conservation in office buildings, in which the standard Illuminating Engineering Society recommended illumination levels for typical office tasks were questioned on the basis of new experimental data. This report, with actual operating experience in a large number of Federal buildings after implementation of the 50/30/10 guidelines, indicates that somewhat lower illumination levels can give adequate light for office tasks. Finally, additional information produced by the National Institute for Occupational Safety and Health, and by FEA's recent Symposium on the Basis for Effective Management of Lighting Energy, indicate that energy savings in lighting can be accomplished without jeopardy to safety, health, or performance.



[illegible] Congress | [illegible] Session | COMMITTEE PRINT

POTENTIAL FOR IMPROVEMENT OF
ENERGY EFFICIENCY OF AUTOMOBILES
AND MAJOR APPLIANCES

PREPARED FOR THE
SUBCOMMITTEE ON ENERGY AND POWER
OF THE
INTERSTATE AND FOREIGN COMMERCE
COMMITTEE
UNITED STATES HOUSE OF REPRESENTATIVES

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U.S. GOVERNMENT PRINTING OFFICE
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# TECHNICAL OPPORTUNITIES FOR IMPROVING THE ENERGY EFFICIENCY OF THE NATION'S APPLIANCES

(By [illegible], Energy Research and Development Administration, Washington, D.C.)

## I. INTRODUCTION

Appliances are defined here as including water heaters, refrigerators, freezers, ranges, television sets, room air conditioners, clothes dryers and washers, dishwashers and any of a number of small appliances normally found in residential use. Excluded from this discussion are central climate conditioning systems such as furnaces, central air conditioners, heat pumps, and large commercial appliances.

Appliances presently account for about [illegible] of total U.S. energy consumption. Electricity and gas represent the dominant forms of energy required to operate appliances, with energy delivered in the form of electricity accounting for about [illegible] of all appliance energy consumption. Only in the case of the New England and the Middle Atlantic states does fuel oil and liquefied petroleum gas account for some portion of water heater fuel consumption, and for this appliance it amounts to no more than [illegible] of total energy for hot water heating.

Residential-type appliances are found primarily in the residential sector and account for about [illegible] of appliance energy consumption. However, they are used to some extent in the commercial sector also. Energy consumption by the Nation's residential appliances has been determined by the Federal Energy Administration during the development of the Project Independence Report. Data on energy consumption, for the major energy-consuming appliances, are given in Figure 1 below. This information comes from the Final Task Force Report: "Residential and Commercial Energy Use Patterns [illegible]", November [illegible] Volume 1. The data have been corrected to give primary energy consumption, reflecting total energy consumption including electric power plant losses of [illegible]. [illegible] They have also been interpolated and extrapolated [illegible] on the basis of trends that appear in the report cited above, to [illegible] and [illegible].

[illegible]

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| [illegible] | [illegible] | [illegible] |
| Total | [illegible] | [illegible] |

[illegible]

## II. [illegible] OF [illegible] APPLIANCE ENERGY CONSUMPTION

One policy option for [illegible] the energy consumption of the [illegible] [illegible]

Electricity is a special energy form which has a number of [illegible] [illegible]

1. Reduced capital investment requirements for facilities [illegible]
2. [illegible] environmental benefits associated with [illegible] [illegible]
3. Reduction in the pace at which fundamental national policy decisions must be made [illegible] [illegible]

## III. [illegible] ENERGY CONSERVATION [illegible] IN APPLIANCES

The most appropriate energy conservation measures vary from appliance to appliance and according to the fuel, electricity or gas, which powers the appliance. [illegible]

### A. Water heaters

Hot water energy consumption might be reduced in two ways: [illegible]

[illegible]

About [illegible] [illegible]

Energy saving benefits can be [illegible] [illegible]

### B. [illegible]

The appliance [illegible] [illegible]

[illegible] [illegible]

[illegible] [illegible]

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# THE DESIGN OF ELECTRICITY TARIFFS

Charles J. Cicchetti, Ph.D.[1]

[illegible]

(Text adapted from Public Utilities Fortnightly, Vol. 98, No. 5 (August 26, 1976), pp. 25-33.
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### *Abstract*

*This paper discusses time of day pricing as a method of pricing electricity which could be more widely adopted in this country. Ten basic reasons are enumerated as to why time-of-day pricing produces beneficial effects.*

The design of electricity tariffs, as well as their level, has been a source of consumer outrage. Many thoughtful critics wonder out loud, "How can volume discounts for electricity be offered at a time when energy conservation is widely advocated and each year electricity prices are increased because of growth in use?"

Consumers are upset over their increasing electricity bills and angered by the conflicting explanations given by utility spokesmen. In 1973 they were told that increasing prices were due to the higher costs of increased consumption, but in 1974 the same spokesmen blamed higher prices on conservation efforts. There is little comfort from the fact that within the industry there are simple explanations for the apparent inconsistency in these two statements. But many, and their ranks are increasing, feel that a different tariff structure would, in addition to making better economic sense, eliminate much of this confusion over tariff schedules by communicating varying costs directly to the consumer.

Behind the conflicting explanations for rising prices is the concept referred to in the industry as load factor. On the one hand, if increased usage at times in which system peak is likely to occur makes it impossible to avoid the need for new capacity, the cost of building new generating capacity will result in increased unit prices. According to utility spokesmen, this was the case in 1973. On the other hand, the greater the use of existing facilities, the greater benefits there will be in holding down costs and prices for all customers. This latter phenomenon explains the 1974 statements, when conservation apparently led to a reduced use of existing facilities without diminishing the need for capacity and thus resulting in higher average costs. The effort to design tariffs which incorporate both these considerations simultaneously has been the main thrust of my involvement in the electricity tariff controversy in the United States.

Eliminating volume discount pricing and the tariff philosophy of accountants, who do not seem to have been informed about changing use patterns, and substituting time-of-day discounts is the particular reform I have stressed. The reasons why I have come to this position will be discussed, how it may be implemented, and then some of the other tariff reform alternatives offered, especially with low income consumers in mind.

## Time of Day Pricing of Electricity

Ten reasons time-of-day electricity price reform makes the most sense are listed below and discussed each in turn. They are as follows:

1. Cost minimization for the utility;
2. Equity and fairness in tariff structure;
3. Social welfare maximization and economic efficiency;
4. Load factor management;
5. Reducing environmental externalities;
6. Energy conservation;
7. Earning stability;
8. Tariff stability;
9. Consumer benefits; and
10. Industrial protection.

### *Cost Minimization*

Efficiently managed electric utilities attempt to minimize costs in different ways. First, the systems planner and engineer attempt to minimize the cost of meeting what they consider to be the future demands and load pattern for the utility and its connecting systems. They do this by using various sophisticated engineering and computer techniques. Their success in these matters is often imitated by many countries around the world. Additionally, electric utilities practice economy dispatching for the operation of the electric system at any given point in time. The unit cheapest to operate is called on line to provide service to meet demands at a particular time and place. Once again, elegant and sophisticated, economic and engineering models are used to practice economy dispatching. The simple fact is that electric utilities cost minimize in both the operation and the expansion of their systems. In the practice of this cost minimization, it is understood that the cost of a kilowatt-hour of electricity varies over time. The first desirable feature of time-of-day electricity pricing is that it will attempt to track the cost minimization calculation of the systems planners and the utility's economy dispatchers by reflecting this cost pattern in the tariff structure. The systems engineers' knowledge of cost would be communicated to consumers and consumers' demands and willingness to pay in the reverse direction.

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### *Equity*

Economists are not the best ones to discuss the question of fairness or equity when it comes to electricity prices. The reason for this is that economists usually try to avoid taking any stand on whether or not two alternatives are fair or equitable; that is, economists are more comfortable at making allocation or efficiency decisions than in making social equity decisions. However, it is frequently asked at electric utility regulatory proceedings whether or not time of day pricing will be fair or equitable contrasted with alternative pricing systems. My response to that has usually been that by pricing a kilowatt-hour of electricity for all customers on the basis of the actual cost of the utility would be the fairest and the most direct way of pricing electricity imaginable. It would be fair in that it would price all similarly produced kilowatt-hours from a cost standpoint alike. Distinctions would not be made based upon total levels of consumption over a billing period and in this way if the fairness criterion is used, the cost of a kilowatt-hour as it varies with time, it can be claimed that equity and fairness have been increased as contrasted with the present system of volume discount pricing. The present arbitrary and often subjective practice of cost allocation would be virtually eliminated since kilowatt-hours produced at the same time would be priced alike other than for voltage differences.

### *Social Welfare Maximization and Efficiency*

The main public policy rule of economics is that to achieve an efficient allocation of society's scarce resources, and at the same time to maximize the social welfare of an economy for a given income distribution, the cost of each good and service consumed by that society should be priced on the basis of the incremental or marginal cost involved in producing and distributing that good or service. Setting second best considerations aside to be adjusted after the basic tariff structure is determined, time of day pricing is a pragmatic attempt to bring this very elegant mathematical policy rule into regulatory proceedings and into practice by the electric utilities in the United States. Consumers would benefit from more stable electric prices. Time of day discounts, that will make it possible for consumers to take advantage of lower cost consumption, will benefit themselves and the utility. Time of day penalties, which will indicate to the consumer when it is that electricity is expensive from a capacity expansion standpoint and operating standpoint, are the very essence of the pragmatic attempt to translate the economist's notion of an efficient allocation of resources into the tariff schedules of electric utilities.

### *Load Factor Management*

As indicated in above, electric utility management attempts to minimize the cost of operating and expanding its systems. The greatest benefits of time of day pricing is that it will add an additional factor to the objective function of system planners when they consider the various ways in which cost minimization might be achieved. When a system planner considers the cheapest means of expanding an electric utility system to meet growing loads, one of those options that should be considered by the systems planner is the possibility of offering discounts to existing customers in order to encourage a change in load patterns and a change in peak consumption habits on the part of consumers. If it is cheaper to give discounts to existing customers, and thereby encourage a shifting in use, rather than to acquire a more expensive new investment or undertake more expensive operating costs, the tariff approach should be undertaken and, if available, it would be willingly undertaken by the nation's utilities. Time of day pricing, along with the generous use of interruptible tariffs for the larger volume customers, will greatly hold down the need for new generating and transmission capacity in the United States. Note that, frequently, interruptible rates are down played in the United States because it is pointed out that no single firm could afford a long interruption. However, in other countries several industrial customers are sometimes packaged into an interruptible group in which no single firm has to be interrupted for the entire peak period, but collectively, the capacity saving can be great and so should the size of the discount. In these ways the need for new capacity can be reduced without necessarily diminishing the use of energy and the concomitant increase in economic activity and jobs for the nation.

### *Environmental Externalities*

Environmentalists entered the debate on electricity pricing just prior to consumer and low income groups who were concerned with rising prices. For the most part, environmentalists have been opposed to the external social cost associated with the construction and operation of electric generating plants and the transmission systems that connect such generating plants with the consumers of electrical energy. Since time of day pricing is expected to reduce the need for new generating and transmission capacity, environmentalists, who are concerned about such matters, would find that under time of day pricing the amount of new electrical generating and transmission capacity needed for the United States would be less than under any alternative form of electricity pricing that might be considered. On the operation side, many electric power plants have peaking units which are old generating plants which are often very inefficient to operate. Such plants are typically fossil fuel users and are the most polluting from a particulate and sulfur dioxide standpoint. Because time of day pricing would shift use away from such inefficient, and therefore polluting units, time-of-day pricing is also expected to have a desirable pollution avoiding effect.

*Energy Conservation*

Many people in the United States are concerned with our uncontrolled and seemingly unending growth spiral of energy consumption. Time of day pricing would discourage the most expensive aspect of this energy consumption by helping to avoid the use of new and more expensive generating and transmission facilities. Time of day pricing would also result in a shift to more energy efficient base load and intermediate load units and away from inefficient peaker units and old fossil fuel plants which are inefficient from an operating standpoint. It is quite possible, however, that if energy is measured in terms of total kilowatt-hours consumed, as opposed to total amount of energy that is required to meet a given load, that time of day pricing might actually encourage a greater use of electrical energy. To some this greater use may seem inconsistent with energy conservation, but time of day pricing will improve the energy efficiency of the actual level of electricity consumed in the United States, and that is a positive improvement in energy conservation.

*Earning Stability*

One of the serious problems today in electric tariff controversies is that many have selected a tariff design objective which is inappropriate. To many the goal of electricity tariffs is to achieve gross revenue stability. This is a short run and foolish objective for those who adopt it. Electric utility gross revenue stability can, of course, be achieved by charging as much money "up front" as is possible and which the electric regulatory commissions will permit. In this manner the goal of gross revenue stabilization can be achieved. But that leaves very little revenue that can affect the discretionary use patterns of the customers of an electric utility. It also means retaining volume discount or promotional pricing. It, therefore, means that nobody will be getting signals as to when it is cheap to consume electricity from the standpoint of generating capacity cost or system operating cost. A pricing system, based on time of day costs, that attempts to tie revenues for the utility and costs for the utility together is the essence of time of day pricing. But the objective that the pricing system is meant to achieve is earning or net revenue stability, and not the incorrect goal of gross revenue stability. The controversy surrounding electricity tariffs often becomes a disciplinary conflict with accountants, who are taught and trained to think in terms of gross revenue stability, and economists, who are taught and trained to think about earnings or net revenue stability. The two are in conflict. The economist's position, which closely follows the engineering cost minimization position, is the most desirable pricing system for our nation's electric utilities.

*Tariff Stability*

There is no rule of nature that requires the unending round of electric utility revenue increases to continue unabated year in and year out. The customers, the investors, the regulators, the utilities themselves must and would all find a common interest in ending this vicious and unending spiral. By pricing electricity in a way that varies with the costs the utility expends over time, this chain can and will be broken by helping the utility and the customers of the utility find tariff stability. This objective will be furthered because changes in consumer use patterns will result in changes in revenue and costs that will move in the same direction and tend to offset one another.

*Consumer Benefits*

As an economist, perhaps the best reason that electricity pricing reform makes sense for the Nation is the expected consumer savings. Recently, the British and French, who have been practicing time of day pricing for almost 20 years, have been asked to estimate what they think the annual savings of total electric utility cost are by having time-of-day pricing installed for industrial customers in both countries and on an optional basis for residential customers in both countries. Total installed generating capacity in both countries is quite similar to one another in total size. Both have approximately 50,000 megawatts of installed generating capacity. They both have estimated a similar savings in annual cost for that level of installed capacity of about a quarter of a billion dollars per year. These estimates do not include savings in operating costs that are undoubtedly associated with the change in the time pattern of use of electricity.

If we look at the United States, which has an installed capacity of about 10 times either France or England, a similar annual savings would be approximately $2 1/2 to $3 billion per year for the capacity cost saving alone. Additionally, the French have made another calculation. They have also estimated what the savings would be if, in fact, they sold the same amount of electric energy today, but using the load patterns that existed 20 years earlier when time-of-day pricing was first introduced. The French estimated that their annual savings would probably be five to six times the quarter of a billion dollar savings that already has been mentioned. Additionally, there are significant operating cost savings that are expected in the United States. If our industry were as responsive as the French and the English, annual savings of more than $10 billion per year could be expected. By holding down costs all consumers will benefit. Furthermore, by offering time-of-consumption discounts all who can and do switch will save additional money.

*Industrial Protection*

Industrial uses of electricity in the United States were priced in such a way that individual customer load factors were improved. Today this incentive is in conflict with economic, environmental, and conservation objectives. Industrial customers are typically good system load factor customers, who would benefit from time-of-day pricing. However, the volume discount pattern of pricing does not provide the pattern of incentives that will encourage them to save the utility money. Time-of-day pricing will encourage the good system load factor customers to become even more so. They will also encourage very poor individual load factor customers, who use short duration but intense power, to shift such a use to off-peak discount periods.

In today's hostile political climate, volume discounts are untenable. Replacing them with time discounts will not destroy industry and cost much needed jobs; instead, it will benefit them.

With such dramatic savings to be gained, whether it is characterized by using any of the 10 objectives that have been mentioned previously, there is a strong and undeniable case for time-of-day pricing in the United States. Now let us turn to the second part of this discussion: How the particular problems of low income consumers can be taken into account.

## The HOW of Time-of-Day Pricing

Time-of-day pricing has many names. Sometimes it is called peak load pricing; sometimes it is called incremental or marginal cost pricing. Each name attempts to be descriptive, but because there are several names that might be used, it can be inferred that none of the titles by themselves is sufficiently all encompassing to describe the many characteristics that are implied by any of them. If one thinks in terms of incremental or marginal costs, it is important to understand that there are 8,760 hours in a year, several voltage levels, and various generating stations and customer load centers. Therefore, the number of possible margins that might be used for setting marginal cost prices is extremely large. Electricity tariffs, therefore, have to be based upon a compromise between the reality of a virtually unlimited number of margins and the pragmatic requirement that electricity tariffs must be understood by various customers of the electric utility. The traditional separation of cost for electric utilities into generating, transmission, and distribution, along with distinguishing between energy and capacity costs, is a desirable first cut that is useful to retain when describing the time pattern of the structure of the electric utility's cost. This pattern of cost, as it varies over time, can then be used to develop tariffs which are simple and easily understood by the customers of the electric utility system.

Economists have used a device that goes under the Latin phrase "ceteris paribus," meaning "other things being equal." To the mathematician, when that phrase is utilized, it means taking a partial, rather than a total, derivative. In short, it means holding things constant, which are otherwise likely to vary. In determining the marginal cost of the various dimensions of electric utility cost, use of the ceteris paribus or partial derivative concept makes life much less complicated than it otherwise would be.

To explain how this works, refer to a concept which has received quite a bit of attention in electricity tariff debates. The concept is called "long-run incremental cost." It is used to determine the capacity cost of the electric utility system looking into the future. It is determined by estimating what the future demand for the utility will be in the years immediately ahead, for example, over the next 10-year period along with the expected pattern of that future load. Such projections are a basic ingredient for designing the least cost plans of the electric utility system by adding plant and equipment to its currently available system. Once the development plan to achieve the least cost expansion and operation for the electric utility in the near future has been determined, the appropriate way for calculating long-run incremental capacity cost is to look at the cost that would be entailed if demand were to increase in such a manner that the entire plan was moved forward by one year. The difference in the present value of the two cost structures converted to a per kilowatt cost basis is the long-run incremental capacity cost. If reoptimization would take place, and that information is available, it should be used. In practice this might reduce to the cost per kilowatt of moving a single plant planned for the next 5 to 10 years forward by 1 year.

An alternative, if information is more readily available, would be to ask what would be the reduction in cost if the entire plan were postponed by 1 year. For a large electric utility system like those found in the United States the difference between the two approaches is not expected to be great. The calculation thus made uses the concept of holding other things constant, ceteris paribus. It is quite simply the partial derivative of cost holding all things constant other than the level of supply, which is required to meet the expected level of demand.

When calculating long-run incremental cost there are likely to be differences in fuel costs if new, more efficient plants were moved forward or postponed 1 year. It is appropriate to net out such cost savings or penalties from the capacity cost in making such a calculation; this step has sometimes been overlooked or omitted by some who mistakenly limited the concept to capacity cost differences. All those who participate in electricity pricing discussions should make certain that the correct concept is being utilized. The systems planners will be more likely to understand the economists when the proper definition is used.

If one looks at the operating side of an electric utility system, once again a partial derivative concept might be utilized to measure marginal costs. Indeed, economy dispatch makes use of a concept called System Lambda. System Lambda is simply the derivative of the total operating cost of providing electricity with respect to the quantity of electricity supplied. Operating costs are minimized by the system dispatcher for an electric utility by utilizing the available unit with the lowest system lambda at any given time and place in order to meet the load pattern of demand placed upon the electric utility. System Lambda varies over time and across places and it is, therefore, a very important concept that reflects quite dramatically the time pattern of costs.

Transmission costs are an important ingredient of the cost structure for the electric utility. They vary incrementally based upon the voltage level that the electricity is being transmitted at, as well as the distance and the quantity of electric transmission that are taking place. One can once again use a partial derivative, ceteris paribus calculation in order to calculate the extra cost of transmission at different times over different lengths and at different voltage levels. Variations in transmission costs calculated incrementally can and should be reflected by an electric utility in its time-of-use cost structure. The basis for this calculation of incremental costs is more long-run than operating costs, but closer to the present than incremental generating costs. The basis for the variation in costs is both extra line miles and transformer capacity per kilowatt of additional demand at the various voltage levels.

Another major category is distribution cost. Distribution and transmission costs are distinguished by including in distribution costs that component of transmission cost that can be easily identified with a particular customer or group of customers further down the distribution and transmission system. Transmission costs, on the other hand, are those costs of moving electricity from generating plant to consumer which are more common or collective to all customers who are supplied in a similar geographic region. When it is possible to calculate the additional costs of supplying (including metering) a particular customer at a particular voltage level, these can be used to establish the distribution or customer cost component of supply.

The final step in analyzing costs is most important because it is the basis for the assertion that a kilowatt-hour is not a homogeneous commodity from the cost standpoint. There are several ways of incorporating that simple fact into the final calculation that can and must be made before tariffs can be designed. There are 8,760 hours in a year. However, each hour is not equally likely to have demand exceed the available supply of the utility. The available supply of capacity of the utility refers to the generating and transmission capacity which limit the ability of the utility to meet the demands that might be placed upon it. Additionally, the likelihood of demand exceeding supply must also take into account the fact that we are talking about demand relative to an expected or anticipated supply, not the nameplate generating capacity of the system in question. Therefore, scheduled plant maintenance and repair schedules, which one has prior knowledge of and which will mean certain units are unavailable during certain times of the year, must be brought into the calculation of the probability or likelihood of demand approaching or exceeding the capacity of the electric utility.

Once the above has been determined, one can calculate the probability of a loss of load; that is, the probability of demand approaching or exceeding the available capacity of the electric utility. It is important in recognizing the time pattern of this probability of demand exceeding supply to assign the cost of expanding the electric utility systems, the long-run incremental cost of generation and transmission capacity, to those hours for which the likelihood of demand exceeding supply is great relative to those hours of the year for which it is small.

For some electric utility systems there might be some intermediate or shoulder periods for which the probability is not quite as great as those hours which we might identify as peak, as opposed to those hours which we might identify as off-peak. There is no simple generalization that might be made in advance to fit every individual electric utility system in the United States;

nevertheless, it is possible to define those hours (typically about 1,000 hours) in which we think the cost of expanding the system when demand increases is greater than those when demand growth does not imply capacity expansion.

If we have done all the above, we can calculate for those hours which are similar in terms of peak, off-peak, and intermediate probability of loss of load, the cost of running the system expected to operate during those periods, and assign the incremental generating and transmission costs to peak hours on either a kilowatt or kilowatt-hour basis (depending upon whether we want to perform an additional step of division). In addition, we can determine transmission costs at different voltage levels and customer costs further down the distribution system. Once we have done that, the structure of costs for designing tariffs is complete.

The tariffs that would logically follow from such cost structure would not be so difficult for the industrial customers of an electric utility who would readily understand them. Therefore, we do not need to worry about major additional simplifications to develop tariffs for that class. Additionally, most large industrial users also have metering equipment currently installed for which we can measure use patterns sufficiently detailed to encompass the cost structure described above after it is translated into a tariff structure for this group. The residential and lower volume customers present a greater simplification problem. A discussion of this will follow. For now, I strongly urge that once this basic cost information is known, that time-of-day prices for industrial customers be implemented along those lines with due speed throughout the entire United States.

To some the above may sound too theoretical. Therefore, the actual experience of France and the United Kingdom in setting time-of-day varying rates is described. In a general way there are some similarities in the pricing systems of these two countries. First, since the 1950's both countries have adopted the economic and engineering principle of marginal cost pricing and have been moving forward in the direction of implementing time-of-day pricing. Today, almost all industrial customers in both countries consume electricity under time-of-day and seasonal pricing structures. Smaller customers in both countries, after paying basic customer fees, are charged for electricity according to either a flat kilowatt-hour tariff or an optional time-of-day tariff. In France about 20 percent of the domestic customers select such a time-of-day pricing plan. The percentage of kilowatt-hour sales in the United Kingdom is greater. Overall, residential customer consumption is substantially less in both countries than in the United States, and both countries have weather sensitive winter peaking loads. The customers who have adopted the time-of-day pricing option are most likely to be the heating customers.

The French distinguish between their customers very finely. For the industrial customer the price per kilowatt-hour varies over five time periods: peak, winter and summer full hours (intermediate), and winter and summer slack hours (off-peak). They further vary their rates by region and voltage levels. The customer also pays a fixed charge to cover both the distribution costs of the system that depend directly on the client's own peak consumption and a portion of the costs that are intermediate between collective costs and the individual customer-related costs. This latter refinement is related directly to the large hydroelectric proportion in the French system.

A formula is applied in order to give a price incentive to customers who adjust their capacity requirements to system needs. If use at more costly times increases, the customer pays a penalty. If alterations in use patterns are made to benefit the system, prices are reduced. Setting aside time-of-day variations in energy charges and other use-category effects, this contractual formula has been estimated to postpone the need to construct a new generating unit of about 700 megawatts in size for a full year. A further saving of about 1,300 megawatts is attributable to the industrial tariff or *tarif vert* for a combined estimate of 2,000 megawatts in a system peak of roughly 30,000 megawatts.

Further adjustments are made for high load factors, self-generation, emergency, and short-term customer needs. Such refinements are primarily made in the fixed charge. The basic charge for a contracted kilowatt is about $66 per year. It is higher for self-generation and lower for emergencies. Additionally, the energy charge varies by a factor of about 8 to 1 in the base tariff and nearly 10 to 1 in the short use emergency tariffs between peak and off-peak. The variation is less for the standby service. The basic peak energy charge is about 6 cents per kilowatt-hour.

Low-voltage domestic customers are sold electricity under the universal rate. Such customers have a contracted fixed monthly charge and a proportional (flat) energy charge. Circuit breakers are used to limit loads. Each tariff usually has a day-night as well as a flat version. Those selecting the day-night differential option pay slightly more than one dollar per month for additional metering costs. The day-night difference is about two to one for an 8-hour night period.

In the United Kingdom, there are area distribution boards who purchase bulk power from the Central Electricity Generating Board. Each board pays an annual capacity charge with various adjustments, as well as an energy charge before fuel cost adjustment of about 1.6 cents per kilowatt-hour for daytime and early evening peak months, about .65 cents per kilowatt-hour for other daytime and evening purchases, and less than .5 cent for all sales between 11 p.m. and 7 a.m. throughout the entire year.

Area boards set their tariffs based upon this purchase schedule. A typical industrial customer is likely to pay a customer charge and a monthly varying capacity charge (with as much as about a 10 to 1 difference between peak and off-peak monthly charges). Day-night differences of about 50 percent are in effect on the energy charge for periods of night-time use. These are typically of an 8-hour duration. Converting to a U.S. price basis this would have been approximately 1.25 cents per kilowatt-hour charge in the daytime and 0.75 cents per kilowatt-hour charge at night before fuel costs adjustment and peak monthly demand charges of about $7 per kilowatt in peak months falling to less than $1 per kilowatt in the off-peak months.

Special terms for interruptible (or flexible) industrial customers with a greater proportion of the revenue collected in the kilowatt-hour charge are also utilized. Prices during peak might be as much as 40 cents per kilowatt-hour, but less than one-fourth of that during the night-time off-peak hours. Capacity charges are collected on a lower (about half the normal) price schedule. But during potential peak periods (up to 50 hours per year), the customer could face a capacity charge typically more than twice the normal peak monthly charge.

The hallmark of the pricing systems in France and the United Kingdom is that they are pragmatic attempts to have prices track costs. The principles articulated above are utilized to design electricity tariffs. This pragmatism is also reflected in the domestic charges in the United Kingdom: since domestic customers are billed quarterly in a staggered manner, seasonal billing is not economic. The basic price is a flat charge of about 3 cents per kilowatt-hour. Previously available off-peak heating tariffs are maintained, but closed to new subscribers. These offered customers 11 hours of off-peak energy for heating only at about half the normal price. Currently, an optional day-night tariff is offered with a slightly higher daytime price (less than 5 percent), a higher quarterly charge (about $2.40 per quarter) for extra metering, but an 8-hour nighttime price of about 40 percent of the daytime price.

It is possible to learn from this European experience, but it cannot be directly transferred to our own country and, therefore, we must consider how to implement time-of-day pricing in the United States. Some of the problems are frequently mentioned by those concerned with time-of-day pricing reform: the questions of meter availability and cost, the impact of consumer response and the so-called shifting peak problem, the problem of allocating cost during a phase-in period between those on the new tariffs and those not, and the subsidiary question of how to deal with large volume versus small volume users.

The question of metering availability is really a very significant question for the smaller volume users. As already noted, the cost of metering is trivial when compared to the monthly bills of the large industrial users, but for the smaller users we must proceed carefully and make certain that we do not undertake tariff reform for which the benefits to be derived are less than the costs. But that is not our only question with meter availability. There are also technical breakthroughs in metering on the horizon that might make some of these currently available meters seem quite primitive. A challenging question for all to consider is whether or not we should go forward with time-of-day pricing reform unless we know when some of this new metering technology might be available and what its cost might be.

The second problem area is predicting consumer behavior. Implementing time-of-day pricing is not something you do and then forget. Load research and monitoring must be continued in order that, with any prospective changes in use patterns, modifications in the pricing practices on one schedule or another may be utilized in order to help avoid creating new problems and new costs. In short, systems planners must be able to use pricing incentives in order to find ways of helping to hold down costs. In the final analysis, systems planners will pick the cheapest solution for all customers and for the utility as well when it comes to deciding what is the best way to supply system needs. The introduction of time-of-day pricing and the associated consumer response to the calculations of the systems planner would be a dramatic cost saving reform.

There is also a problem of allocating cost between various customer categories, especially when some of the users will be put on time-of-day pricing (typically the larger volume ones). How will the revenue requirement be allocated between these groups? What will happen if one group generates too much revenue and another group too little revenue? These are really challenging questions that the regulators must begin to tackle.

There are various implementation plans for the large-volume users. Let us consider three options. First, we might have a two-part tariff with customer charges based upon the customer's maximum demand to recover demand cost and a time-varying energy charge with capacity costs of generation and transmission factored into it on a peak kilowatt-hour charge. Second, we might have a three-part tariff with a customer charge to recover the distribution cost, a time-varying energy charge (with the highest running cost plant during peak hours serving as the peak kilowatt-hour charge), a capacity charge based upon the hours of the day and perhaps months of the year that consumption occurs. Third, an interruptible tariff with very large discounts is possible due to very low capacity cost responsibility. Penalties for failure to accept interruption, however, should also be high.

Time-of-day and seasonal discounts as a substitute for industrial volume discounts make sense for customer and utility alike. Accordingly, it is important to demonstrate this fact for industrial users by performing typical bill analyses, as well as surveying these users through statewide manufacturing associations. Plans to do this have been tentatively made in several States. Consumer understanding, even for large-volume customers, is an important step.

The final question for large-volume users is to determine the speed of implementation. Several States are moving to the position that cost-based tariff structures (as the economist and engineer rather than the accountant would describe them) must be implemented for industry, but there are still options present. First, all large customers could be placed on cost-based tariffs and their level could be constrained by current revenue allocation formulas between the various customer classes. Second, cost-based tariffs could be implemented and any excess revenue anticipated could be used to reduce customer cost and off-peak prices in order to create the maximum incentive for system cost reductions by keeping all excess revenue in the class. Alternatively, other classes could be subsidized if excess revenue were to be generated. This latter step is probably illegal and it is not good economics, but it has political support in some circles. Third, optional time-of-day tariffs based upon actual cost could be offered, with future revenue increases for the class being placed disproportionately on those who refuse the option. Even if use patterns do not change when metering costs are trivial, as they are for the industrial class, time-of-day pricing is superior to the existing accountant's approach as a cost-allocating device. It is, therefore, important to implement it to the greatest extent possible for the industrial users. It will be good for both that user category and for the utility and, therefore, for all customers alike.

For the smaller volume users, there are several approaches, but in this category avoiding uneconomic metering costs is a more significant constraint. The various alternatives being considered for implementation can be summarized as follows. First, time-of-day schedules and meters and a sample of customers in the category could be developed in order to find typical use patterns by time-of-consumption, and then use these data to develop a time-of-day rate for classwide bills. In addition, an optional meter can be offered for those customers who think they are atypical and can save money if they install meters at their own expense.

A second approach is to start with the larger small-volume customers and implement time-of-day pricing for them. If in retrospect the cost savings outweigh the metering cost, the time-of-day pricing could be extended to the next largest of the small-volume customers and the analysis repeated. This process could be repeated as long as the benefits exceed the cost. Third, tariff experiments can be undertaken to measure the response of customers to time-of-day varying tariffs and their willingness to shift use away from peak. Such experiments could complement the first two alternatives, but customer compensation is absolutely essential in these experiments.

However, for residential customers, plans to implement either of the first two approaches should not be delayed by any pricing experiment. But only by pricing experiments and load monitoring research, even after new tariffs are introduced, can we determine how to design tariffs and manage loads. Total class revenues can be collected in many ways even with the time-of-day adjustment. Only by such experiments can one find the level of sensitivity that can best track actual costs, manage loads, and have the greatest impact on reducing the cost of generating electricity.

Finally, a tariff option can be offered in a wide variety of formats even for the smaller volume users. The fact that both the British and the French ultimately went this route should not be overlooked. There are several different forms of tariff at the low volume level that can be considered. First, a two-part tariff with a customer charge and a time-varying kilowatt-hour charge could be implemented. A second alternative would be to have a load-limiting three-part tariff with a customer charge, time-varying energy component on a kilowatt-hour basis, and a subscribed maximum demand with charges varying for excesses at different times. Third, less complicated load-limiting tariffs with seasonal emphasis and with or without time-of-day varying energy charges could also be considered. And finally, various combinations based upon metering availability and day-night and seasonal variability can be introduced and considered.

It is important not to implement tariffs if the cost of metering outweighs the benefits in utility cost savings. This may be decided upon by the individual customer in the case of residential customers, but it is important to go forward with time-of-day metering for industrial customers, if only as a cost allocation improvement device and because it will benefit both the utilities and industry. Time of consumption discounts as a practical, economically efficient and politically desirable alternative to volume discounts is a reform whose time has come. When understood, its beneficial effects will be widely embraced. The development and demonstration of an applied methodology and implementation strategy are now the tasks at hand.

## Other Tariff Reforms

Time-of-day pricing reform, which in the eyes of utility executives responsible intervenors promote, is not the only reform recommended by citizen activitists. Some suggest inverted rate pricing or large-volume penalties. Some recommend so-called lifeline rates and some recommend public ownership. Reversing the current practice of volume discounts and creating volume penalties are sometimes offered as a panacea both because of the rising cost problems industry faces, and also because it is fair. But reversing the "tilt" would be likely to lead to large-volume user cutbacks or abandonment of service that would result in higher prices for the remaining customers. Additionally, any conservation that took place under such inverted rates would erode revenue at the most highly priced portion of the schedule. Unlike time-of-day pricing, there is no guarantee that this reduced use would correspond to the highest costs of the utility. Therefore, inverted rates are likely to lead to serious earnings and revenue erosion problems. Thus, rather than breaking the annual rate increase chain, they are likely to extend it.

Another category of pricing reform is sometimes proposed. It is the so-called lifeline rate. Its intended purpose is to help the poor and the elderly. It would make electricity available at a very low, or even zero, price for a given level of use. Viewed as a tilt in the direction of the poor, it would convert electric utilities and public service commissions into welfare agencies. All the problems of insuring that nonpoor do not benefit would be present; e.g., adding additional meters in two-family homes, luxury apartments, second homes, etc.

Economists frequently embrace the acronym TANSTAAFL (there ain't no such thing as a free lunch), which quite simply means that providing kilowatt-hours below cost requires a decision to tax other customers or stockholders to make up the subsidy. Such decisions are not easily made by electric utilities or public service commissions and, in fact, may be illegal.

Income redistribution is undoubtedly necessary but it is the job of government, not private regulated industries. Legislatures and elected officials must do their jobs, while always keeping in mind that what poor people need is money. If a legislature passed a lifeline tariff and provided the money for subsidy directly to the utility or to the customer in the form of an energy stamp, or explained who should pay into the fund to finance the subsidy, electric utilities and public service commissions would have less trouble with poor-people-oriented or tilted electric rates.

Finally, in this regard, many of the current advocates of electricity pricing reform, who have a pro-low-income stance, are missing a very fundamental point. First, let me underscore the fact that declining block volume discount pricing must be eliminated. Fifty years ago electric utilities used to peak in the evening when residential users of electricity all turned on their electric lights. Most tariffs in the United States today are designed with either high front-end separate charges or very high prices for the initial kilowatt-hour of electricity consumed.

Proponents of volume discount or high front-end pricing argue that this is the way to collect the fees from consumers to pay for large generating and transmission costs. But a new capacity is not built for a lighting load in the United States. Instead, it is typically built for a space-conditioning load. Further, a separate charge for potential peak hours of electricity use to collect generating and transmission capital outlays should be adopted, especially for the large-volume industrial, commercial, and residential users.

The low-income electricity user whose use is primarily off-peak is paying a full share of generating and transmission capacity at a time when his contribution to peak is either zero or trivial. If we could meter time of use at very low costs, this factor should, and with the reform that has been advocated, would be recognized in a way that would lower electric bills for the low-income consumer. Short of low-cost metering, participants in electricity rate proceedings should insist that all generating and transmission costs should be eliminated from the customer charge and early block charges. In most States, if only meter costs and specific customer-oriented distribution costs were permitted to be collected up front and all other costs collected on a flat (or time-varying basis), the reduction in low-volume consumer bills would be staggering. Additionally, such a tariff is much closer to the economists' notion of incremental cost pricing than the tariffs currently in existence. Such a change is both more economically efficient and pro-low-income, and for these reasons the argument in favor of this step is compelling.

When the future of energy prices is viewed, the potential of a rapid reform of electricity pricing appears relatively optimistic. We shall be well down the road towards redirecting the wasteful thinking of American industry and consumers by providing ways to save money and energy.

# OPPORTUNITIES IN ELECTRICAL LOAD MANAGEMENT

Douglas C. Bauer, Ph.D.[*]

## Abstract

*The importance of reliable and sufficient supplies of electricity in our economy, coupled with the substantial and increasing economic, energy, and environmental costs associated with its production, make it essential to insure that its development incorporates maximum practicable efficiencies. High among the underexploited opportunities for efficiency is load management and its complement, structural rate reform on the basis of long-run marginal costs. The deterioration of load factors (average load/peak load) has aggravated financial stresses on the electric utility industry already burdened by inflationary pressures that have caused marginal costs to consumers to increase in constant dollars. Initial FEA modeling work projects that load management could have the effect of decreasing oil consumption by about 1.3 million barrels per day while maintaining a kilowatt-hour sales growth rate of about 5 percent per year. Capital savings in plant expansion would be about $40 billion. From a fuels management point of view, increased reliance upon nuclear fuel and coal instead of oil and gas could be accomplished.*

*Successive sections of the paper discuss the importance of structural rate changes including peak usage pricing, load management opportunities in space conditioning, heat storage, "cool storage," load deferrals, and load control options. The FEA utility program goals and features are described; these include a synopsis of demonstration projects in 7 States (recently expanded to another 12), the UCAN voluntary commitment program with the largest utilities, and invited regulatory interventions before local public service commissions.*

## BACKGROUND

Electricity demand in the United States grew at nearly 7 percent per year for most of the post-World War II years. This increase is due primarily to increased per capita electricity usage, rather than population, which has grown at a rate of 2 percent per year and, more recently, at less than 1 percent. In 1973, 25 percent of the Nation's raw fuel supply was used to generate electricity. However, because of largely unavoidable inefficiencies in production (mostly in the power plant), electricity accounted for only 8 percent of the total energy delivered to consumers (ref. 1).

For many decades, the U.S. was the leading exporter of energy fuels. By 1960, however, the net balance had shifted. In 1973, approximately 35 percent of the U.S. oil supply was imported from foreign sources. Twenty percent of that imported oil supplemented the 40 percent of U.S. coal supplies which were used to generate electricity. The quadrupling of oil and coal prices during the past year and a half has made the generation of electricity much more expensive and has accounted for most of the rise in electric bills.

The cost of future utility bills will depend on many factors: the rate of inflation, the Nation's economic health in general, the type of fuels used to generate electricity, and improvements in energy conservation and utilization. The problems are complex and encompass both energy supply and conservation, and domestic and international sources of fuel.

Dwindling supplies of domestic oil and natural gas for electricity production will require readily and abundantly available substitutes. Power generated from coal, nuclear energy, or hydroelectric installations is the most usable available substitute for oil and gas. In the long term, the use of solar energy will be increased to satisfy our energy needs, but adequate conventional electric power will still be required.

The key to such a future, however, is a balanced and efficient growth for electric utilities. There remain substantial energy and economic inefficiencies in this sector, not only in the generation of electricity, but also in its transmission, local distribution, and end use. The electrical utilities are also experiencing serious financial stress resulting from rising costs of capacity and generator fuels and steadily deteriorating load factors (average load/peakload). The load factor problem is particularly important because capital requirements are driven by peakloads, whereas revenues are derived from total load. Deteriorating load factors also cause utilities to retain older, inefficient generators to meet peakloads or to acquire relatively inexpensive new peaking generators—typically, simple-cycle combustion turbines inefficiently burning scarce fossil fuels.

At the historic sales growth rate (nearly 7 percent) the electric utility industry would consume 36.1 quadrillion Btu's (quads) of energy in 1985 and face probable capacity shortages. A comprehensive energy-efficiency program, reinforced by increasing energy prices and declining growth of per capita income, could moderate this rate of sales growth to a manageable 5 percent (slightly lower than the most recent Edison Electric Institute forecast) with an associated 1985 energy consumption of 30.7 quads. Finally, an aggressive load-management program could disengage and further reduce the growth of peak kilowatt demand from this moderated growth of kilowatt-hour sales.

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Initial FEA econometric modeling work projects the following 1985 consumption of generator fuels (quads):

| | Coal | Oil | Gas | Nonfossil | Total |
|---|---|---|---|---|---|
| High growth | 12.3 | 8.0 | 3.7 | 12.1 | 36.1 |
| Moderate growth | 9.7 | 5.8 | 3.3 | 11.9 | 30.7 |
| Load management | 10.9 | 3.0 | 3.4 | 13.4 | 30.7 |

As can be seen, load management could have the effect of decreasing oil consumption a full 2.8 quads, or about 1,330,000 barrels per day, below moderate growth while simultaneously maintaining sales growth and increasing nuclear and hydro generation by 1.5 quads above moderate growth and 1.3 quads above the high growth case. It also has the potential to save about $40 billion in capital for plant expansion capacity (see figure 1 a-f) relative to Moderate Growth and $140 billion relative to High Growth (historic).

In addition, electricity's share of total delivered energy could increase from 11 percent in Moderate Growth to 13 percent in Load Management, largely by end-use fuel switching from oil and natural gas to coal- and nuclear-generated electricity. This end-use fuel switching, which would conserve an additional 0.4 quad of scarce fossil fuels, is caused by an 8 percent reduction in the real dollar price of electricity, a reduction made possible by increased capacity utilization.

## ELECTRIC UTILITY RATES

Incorporated into any load management scheme is a basic restructuring of electric utility rates. Utilities have typically structured their rates on the basis of "fully allocated" or fully distributed average costs. This basis led to declining block rate structures; that is, the price of a kilowatt-hour decreased as the number of kilowatt-hours used increased. Such rate structures rarely, if ever differentiate between on-peak and off-peak usage[4], even

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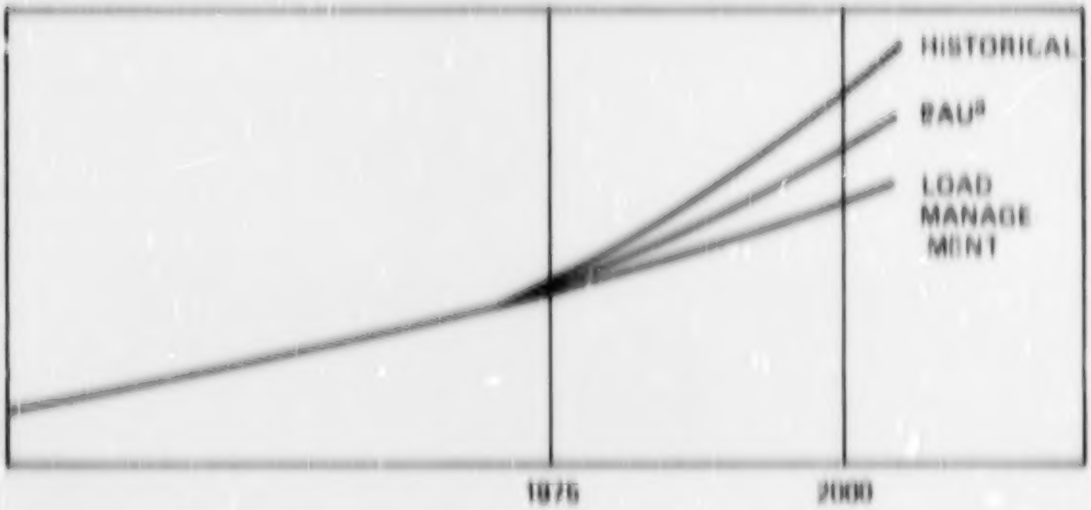
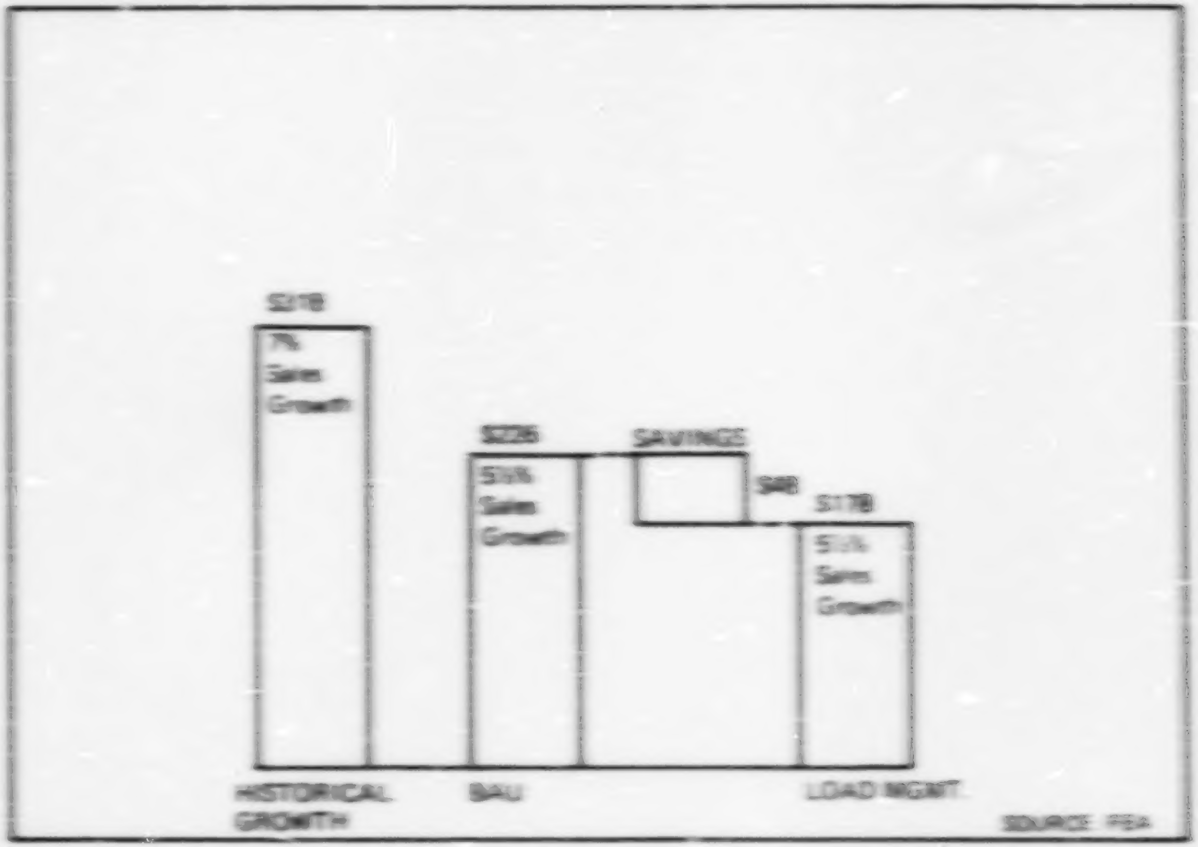
[4] "Peak usage" refers to the point in time of highest demand on a utility system. It may be measured daily, weekly, monthly, or yearly. In a daily increment, peak might refer to the period of time between 4:00 p.m. and 7:00 p.m. when customers demand the most energy.



[a]Business as usual (Edison Electric Institute Forecast, June 1975)

Figure 1a. Electrical generation and use: End-use conservation, high electricity prices, appliance saturation, and demographics are expected to reduce historic growth rates for capacity, and load management can reduce that further.



SOURCE: FEA

Figure 1b. Capital requirements between now and 1985 are substantially reduced.
Historical vs. BAU vs. load management.
(billions of U.S. dollars)

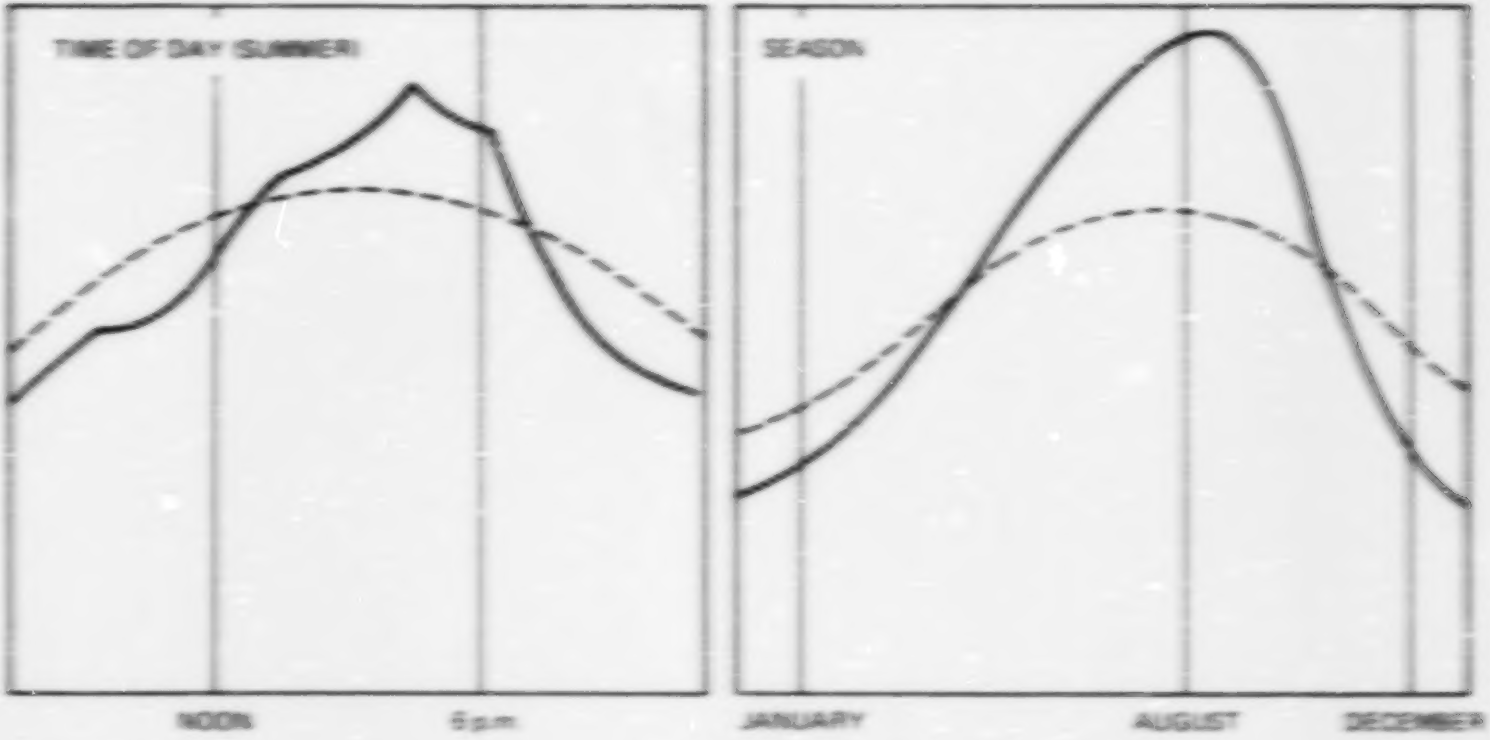


Figure 1c. Load management reduces peaks. How? Peak rates, load control systems, storage devices. (We are now funding seven State demonstrations).

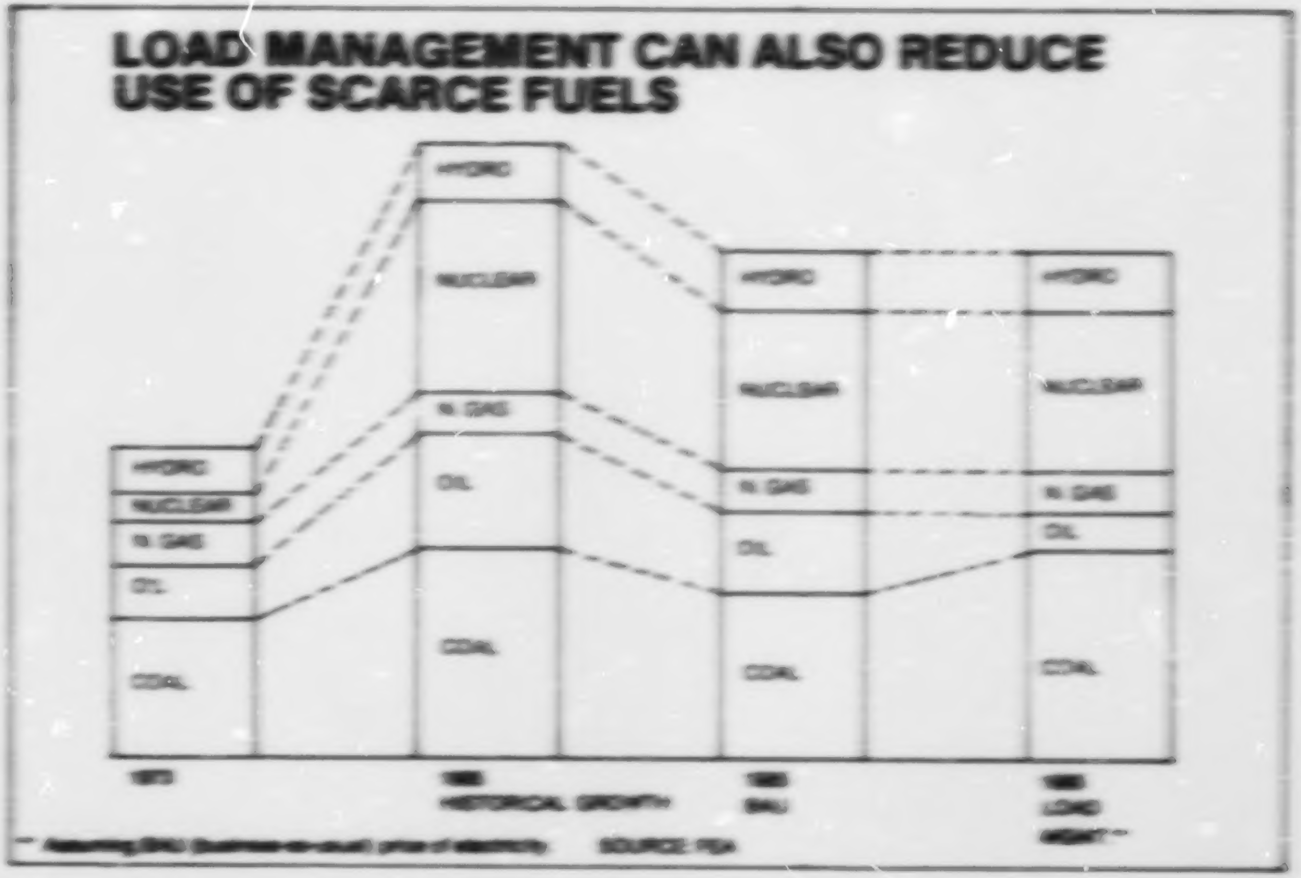


Figure 1d. Load management can also reduce use of scarce fuels.

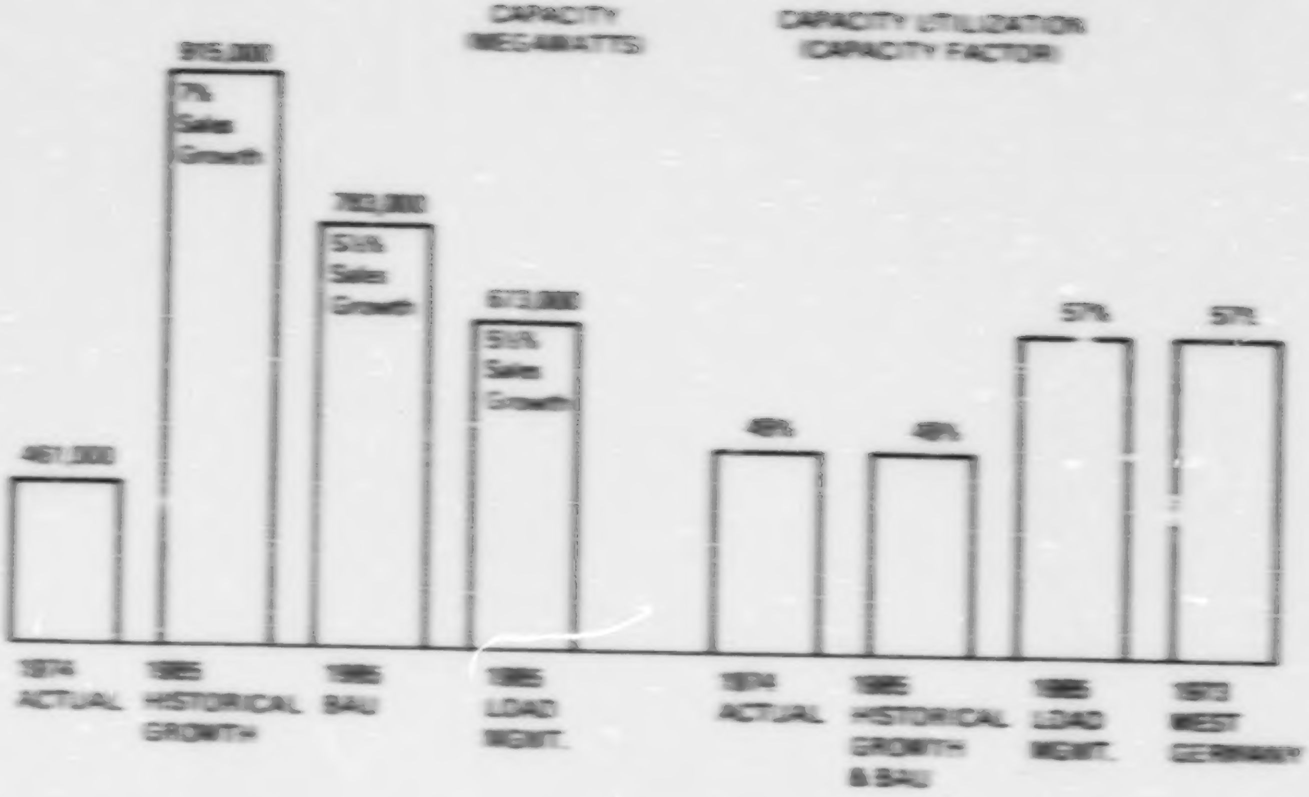


Figure 1e. A load management program reduces future capacity requirements by improving plant utilization.

## ELECTRIC UTILITIES SUMMARY

- LOAD MANAGEMENT IS THE KEY UTILITY CONSERVATION EFFORT–MAYBE THE SINGLE MOST IMPORTANT CONSERVATION MEASURE
  - SAVES $60 BILLION OF INCREMENTAL CAPACITY.
  - ENCOURAGES COAL AND NUCLEAR BASE LOAD CAPACITY SAVING 1,300,000 BPD OF OIL.
  - ENCOURAGES END USE FUEL SWITCHING FROM OIL AND NATURAL GAS.

Figure 11. Electric utilities summary.

though it is clearly the former which is forcing the additional cost of capacity expansion. These rate structures worked fairly well in the past when the incremental cost of capacity was lower than the average cost of installed capacity (ref. 2). Currently, incremental costs exceed average costs. Rate structures do not reflect this fact and, therefore, fail to communicate proper cost signals to consumers.

In the absence of more refined pricing patterns and other load management tools, the industry attempted to simultaneously expand capacity to meet rising demand peaks while promoting the development of new loads off-peak. Utilities with summer demand peaks often promoted electric resistance space heating to fill in their winter valley while continuing to promote air conditioning as well. Winter peaking systems, similarly, tended to promote air conditioning.

## MARGINAL COST (Practical Pricing)

Utilities should now begin to examine pricing policies to insure that their rates adequately reflect the true marginal or incremental costs of service–particularly peak demand costs in the case of electricity–and to provide the proper economic signals to consumers. Prominent economists agree that there is virtually no argument in determining whether or not marginal cost pricing is correct: as a matter of economic principle it is correct by definition. In the case of electric utility companies, rates must be based on marginal costs if economic efficiency is to be achieved (ref. 3). Dr. Ralph Turvey, former chief economist at the Electricity Council of the United Kingdom, stated in reference to cost-based rates that "it is better to be approximately correct than absolutely wrong."

Moreover, there is virtually no argument that marginal costs are of great significance in the case of electric utility rates. It is generally accepted that the cost of providing electricity varies significantly with the *timing* of demand. Additional generating capacity must be built in order for utilities to meet peak demands. In addition, system-running costs are higher during peak than during valley periods. The incremental fuel cost is twice as high on-peak as it is off-peak (ref. 3). As Dr. Turvey wrote (ref. 4):

> . . . rate structure is very important. [It] influences consumer's behavior as to when and how much they use electricity. When consumers use electricity is equally as important as how much they use during a billing period. Like any other set of prices, the rate structure has incentive effects on the buyers: a low rate for extra purchases encourages consumption and a high rate discourages it (ref. 5).

The objective, therefore, is to provide consumers the correct economic signals for consumption of electricity: give them the incentive to economize when the cost to serve is high and to consume when the cost to serve is low. Berlin states that "marginal cost pricing alone permits consumer sovereignty to achieve the allocation of resources that is most consistent with the best interest of the consumer, the company and the public interest (ref. 6).

Accordingly, electricity prices based upon marginal costs would feature the following characteristics:

1. The cost of incremental (future) capacity would be borne primarily by peak usage, i.e., there would be an off-peak discount.

2. Declining block rates would be eliminated, except to the extent strictly justified by fixed customer service costs.

The resultant rate structure would have essentially three parts: a usage (per kWh) charge, a demand (peak system kW) charge, and a service charge. Such a rate would be based upon the best available approximation of actual incremental, prospective costs and would provide the incentives to move loads to off-peak periods and build new loads during such periods.

Potential benefits to be achieved through an incentive system of this type are enormous. In 1973 only 49 percent of installed generating capacity was utilized. If this capacity factor could be increased to 57 percent by 1985, assuming a 5-1/2 percent annual growth rate for kWh usage, the need for installed capacity in 1985 would be reduced by 110 million kWh. This translates to an estimated capital savings of approximately $60 billion in 1975 dollars, which would substantially moderate the need for rate increases. Moreover, the costs of installing the time-of-day meters ($6.9-$13 billion[2]) required for true peakload pricing may now be justified by the benefits, particularly if the technology also embodies remote meter reading and selective load control capability.

Utilities and other systems with rapidly escalating peaks now are expressing considerable interest in load management techniques, which are recognized as a tool for improving system efficiency and limiting the need for capacity expansion. State and local regulatory authorities, faced with consumer opposition to rate increases, environmentalist attacks on utility expansion, and Federal encouragement of energy conservation, are also evidencing interest in strategies to shave peaks and improve system load.

## LOAD MANAGEMENT POTENTIAL

As previously discussed, total U.S. kWh usage has been growing at an average annual rate of slightly less than 7 percent over the last several decades. Peak demand has been growing at slightly more than 7 percent during the same time period. Although both growth rates have been substantially lower since 1973, the pattern of more rapid growth in peak than in usage has become even more pronounced. This has led to a steady deterioration in load and capacity factors, thereby exacerbating utility financial problems and forcing larger rate increases.

These difficulties, in turn, have increasingly forced utilities to purchase low initial cost peaking generators—typically burning distillates or natural gas at inefficient heat rates—to meet peak demands.

A more balanced growth pattern for electricity usage and peak demand would be in the mutual interest of such diverse groups as regulatory authorities, environmentalists, consumers, and utility executives. Such a balanced growth pattern would cut the consumption of scarce fossil fuels in electricity generation, moderate the need for construction of new capacity, reduce the pressure for rate increases, and improve utility revenues. It would also create a more stable base for future coal, nuclear and hydrogenerated electrification of the economy, as an alternative to the direct combustion of gas, oil and oil products.

In order to reduce energy consumption within the Federal Government, the Federal Energy Administration developed energy use guidelines in January 1974. This Federal Energy Management Program was responsible for setting lighting and heating standards in government buildings and speed limits on government vehicles, to name just a few. The Smithsonian Institution rigorously followed the guidelines and reduced their energy consumption 22 percent in the first year. The Institution recently installed a small process computer to provide them with a load management capability. As a result, energy consumption has been reduced an *additional* 16 percent; peak has been reduced by 17 percent. This one example certainly presents a convincing argument for load management.

Several avenues are open, which encourage balanced growth patterns for electricity usage and peak demand. Among those most frequently cited are: rate structures that more closely reflect daily and seasonal variations in the utility's cost to serve, and load management techniques such as system control of deferrable loads and heat storage.

### *Load Management: Space Conditioning*

The increasing saturation of electric resistance heating in winter-peaking systems and air conditioning in summer-peaking systems suggests that the management of these loads is becoming increasingly necessary. In 1966, only 20 percent of new single-family dwellings were constructed with electric heat. In 1974, the figure was 50 percent (ref. 6). This type of electric heating is typically direct resistance heating with no facilities available for heat storage. Electric air conditioning has experienced a similar growth rate: in 1966, 8 percent of new homes were built with central air conditioning, while in 1974 the figure rose to 36 percent (ref. 7).

While it may be argued that peak loads are partially a result of increased use of electric space conditioning, the fact remains that electric space conditioning greatly demands electric energy during system peak. Moreover, this contributes to a waste of primary fuels due to the bringing "on-line" of older, less-efficient peaking units. As a result, the growth of electric heating in winter-peaking systems and electric air conditioning in summer-peaking systems is causing deterioration of annual system load factors.

Avoidance of electric space conditioning during peak periods can be achieved by either interruption of demand or by deliberately designing the system load to draw electric power during off-peak hours. Interruption of residential demands involves the cessation of electric power for periods of time of up to 3 hours. One method of achieving this is through the use of "ripple control," an audio frequency signal sent from the power station to the residential unit. (Interruptable loads will be discussed in more detail in the following section.) An alternative approach to peak avoidance involves the storage of heat during off-peak hours for use during the remainder of the day.

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[2] Assuming $100-$200 per customer for 69 million customers.

### *Heat Storage*

Electric storage heaters consist essentially of a central core of magnesite bricks, which are interspersed with electric heating coils. The bricks are heated to as much as 1,300° F during the night. The stored heat is then drawn from the units as needed during the next day (ref. 8). The storage units range in size from a large, central unit to an individual, room-sized one. The typical charging times are 6, 8 or 10 hours, depending on the particular unit. Heat is dispersed in various ways, depending upon the storage unit. In a "*static*" *heat storage unit*, the stored heat leaves the device by radiation and convection from the case surface. This results in high surface temperatures, but poses no safety hazard. This system is designed to maintain an average space temperature during sixteen hours of discharge time, with no ability to respond to changes in heat demand on a shorter time interval. The unit also experiences a slow decrease in the heat release rate as the storage core temperature decreases. There is no way of forcing the heater to emit heat at a more rapid rate.

*Dynamic heat storage units* (fan assisted) are used where greater flexibility is required for local space heating than can be provided by static storage heaters. Dynamic storage units operate on a forced convection principle and use fans to draw room air into the radiator where it is heated in channels contacting the heater core. Room temperature is maintained by a thermostat, which controls the fan. This unit is much more flexible in controlling room temperature than the static unit.

Space heating using *hot water* distribution of stored heat is similar to a hot air system except that the air heated within the storage core is contacted with water in an air-water heat exchanger. The heated water is then pumped throughout the residence where it gives up its heat to room air in conventional-type hot water radiators. A uniform heat release into the residence is maintained by keeping the water circulating at a constant flow rate and temperature.

### *"Cool Storage"*

Air conditioning load management is a relatively uncharted field. The European countries have gained expertise in heat storage in order to manage their winter-peaking systems. The United States, on the other hand, is plagued by summer peaks and must therefore investigate the potential in storing "cool" as a load management technique.

The two principle techniques for managing electric heating (interruptible electric energy supply during peak and heat storage) cannot be as simply applied for air conditioning management. For example, interruption of electricity supply during peak results in a more rapid temperature change in summer than in winter. This is partially due to the combination of internal heat with solar heat which results in rapid temperature gain while the air conditioning is shut off. (During the winter, these conditions aid in reducing a drop in temperature as electricity is interrupted.) However, temperature drop alone in summer is insufficient to create a comfortable living environment; humidity must also be taken into account. For these reasons, interruption of the air conditioning load is not completely satisfactory.

Many methods for the storage of "cool" have been proposed; however, the most promising alternative is the storage of cold in the form of chilled water using conventional air conditioning equipment (ref. 9). The conditioning of the air space is accomplished by circulating chilled water from storage as required. In this way, sufficient chilled water can be stored by operating the air conditioning system off-peak and the cooling of a building space is done with stored chilled water using no energy during peak.

Although this system is ideal for shifting peak daytime loads to off-peak hours, a considerable economic investment is required in both the storage system and in the air conditioning system, which must be able to accomplish an entire day-time cooling load in a 8-hour off-peak time period.

### *Deferable Loads*

One basic aid in load management is the existence of a deferable load such as an electric portable water heater. In the U.S., household water heaters represent the only load segment having a substantial energy storage capacity. The volume of a typical water heater tank, 60 gallons, is sufficient to avoid any great inconvenience to the customer under normal usage, if the heater is disconnected from the supply for only a few hours. Since the average demand of a water heater during peak is approximately 1 kW, a utility with 200,000 electric water heaters under control could reduce the load during peak by 200 MW (ref. 10).

### *Control Options*

Any discussion of load management techniques such as interruptible loads, heat storage, and time-of-day metering does not proceed very far without mentioning the control aspects of such devices.

The *clock option* is the simplest approach; each individual load unit is turned on and off automatically by a clock-actuated switch. This method is currently being used by a few U.S. utilities to control electric water heater load. The customer acceptance of the control can be secured by reduced rates for off-peak water heating.

In another approach, water tanks are designed with two heating elements, each equipped with its own thermostat. In the tank, cold water enters at the bottom while hot water is drawn from the top. One heating element is near the top of the tank, set at 130° F, while one heating element at the bottom of the tank is set 10° F higher. The upper heating element is permanently connected to the power supply, while the lower element is disconnected by a clock-actuated switch during preset time periods. During these times, power is used to heat water only when the temperature in the (normally) hottest top layers of the water falls below the setting of the top thermostat.

The main advantage of systems using control clocks is their simplicity, which is reflected in the relatively low cost of the hardware. The present cost to the utilities of the basic residential single-phase watthour meter with a built-in, clock-actuated, on-off switch is nearly $60. The register watthour meter with a built-in clock-controlled switch used in conjunction with the two-element water heater costs about $75.

The main problem facing systems with a large number of control clocks is lack of flexibility and a low degree of reliability. For example, clocks often need readjusting. To make a change in the on-off times of the controlled load, each clock must be manually reset, which is a time-consuming, costly process. Moreover, clock-controlled load management systems are not suitable if adjustments in the control schedule are called for by seasonal changes in the load curve or by changes in switching from standard to daylight saving time.

Another indication of the inflexibility of such systems is that clocks normally operate on a 24-hour cycle. The load is turned off even if this is unnecessary, such as on weekends and holidays. Since the clocks run on line power, power outages will delay the on-off times of the load. An extended power outage in an area involving a large controlled load may shift the on-period in such a way as to pose a serious problem for the utility. This situation is improved by providing the electrically driven clocks with a mechanical (spring) backup. The addition of a 10-hour carryover adds $20 to the cost of the meter.

*Ripple control* systems are in widespread use throughout Western Europe, Australia, New Zealand, and South Africa. The system was first tested in Europe over 50 years ago. The technology has steadily improved since then and has gained wide acceptance. By the end of 1973, networks in Europe, Africa, Asia, and Australia were equipped with audio frequency equipment, controlling approximately 5 million receivers.

In this method of load control, a coded narrow-band audio frequency signal is introduced into the power grid at the intermediate or high-voltage level. This signal conveys switching commands to receivers, which are placed at desired locations in the network, usually at the low-voltage (consumer) end.

The main appeal of ripple control load management systems is flexibility and reliability. Depending upon the type of sending-end equipment and the coding scheme used, the number of different command messages ranges to thousands, while the message transmission time may be as short as a few seconds. The messages can be sent manually whenever necessary, or automatically according to any predetermined schedule. As a further step in the degree of control, a ripple-controlled network can be turned into a closed-loop system by using a computer to monitor the network status via hard-line connections to the appropriate network points, and to initiate automatically the transmission of the required command.

In Europe, one of the most important uses of ripple control is the control of charging times on electric storage heaters. However, ripple control signals are used not only for load management purposes, but also for a variety of other functions. These include control of lighting (streets, monuments, public buildings, and display windows), remote switching of multiple rate meters, etc. Since the injected control voltage is present at every wall socket, ripple control equipment can in principle also be used to transmit alert signals to volunteer firemen, policemen, members of the National Guard, etc. In addition, ripple control signals could be used by the utility in the execution of various functions in its own distribution network, such as the shifting of loads from one feeder to another, the closing and opening of circuit breakers, the switching in and out of capacitor banks, the switching of voltage control devices, etc.

To cover the same number of load units, the ripple control hardware is considerably more expensive than a clock-controlled system. This is due to the need for individual receivers which decode the control message and provide the switching function. The ripple control system requires a central control facility and a large number of transmitters to inject the control signal into the network. A hypothetical utility with 100,000 customers and an average of 5 kVA of transformer capacity per customer would have to pay approximately $500,000 for the injection equipment to cover the network. If this equipment were installed to control 20,000 water heaters, the ripple control receivers would cost an additional $2,000,000. Thus, the total cost per customer would average $125. The cost of any new metering equipment, or the modification of the existing meters would have to be added to these figures to arrive at the total cost of the ripple control system. For the sake of comparison, the cost to replace 20,000 basic residential meters with meters incorporating a clock-actuated on-off switch with 10-hour carryover would be $1,000,000 (ref. 8).

*Radio control*, the principle of transmitting control messages via radio waves, offers even more possibilities than ripple control. This is because, in contrast to ripple control, which is limited to the low frequencies not far above the 50 or 60 Hz for which the network has been designed, radio transmissions could be made at much higher frequencies where wide bandwidths, and thus higher information rates, could be employed. As a practical matter, it must be recognized, however, that the electromagnetic spectrum is already overloaded with users, so that the designer of a radio control system works under severe limitations when considering the choice of the system's operating frequency and bandwidth.

The principle of radio control is simple. Radio transmitters are placed in suitable locations (or in vans, aircraft, or helicopters) to cover the network by a sufficiently strong signal. The transmitted waves are modulated by some code containing an "address" for selecting the desired receiver groups, as well as the control message itself. At or near the location of the load under control, a radio receiver detects and decodes the message and performs the switching function as in the case of a ripple control receiver.

The Motorola Company has developed a radio-controlled load management system. The system is in use by the Detroit Edison Company to control the load of 200,000 water heaters. An additional system is now being installed, also for control of water heaters in the area served by Buckeye Power, Inc., of Ohio. According to a recent article in *Business Week* (ref. 1), installed cost of the system used by Buckeye Power will average about $80 per customer. For control of water heaters in areas having a relatively high customer density, the Motorola system appears to be an attractive alternative. On the other hand, it is probably true that for the execution of other command functions (street light, multiregister meters, electric storage heaters), ripple control, with its separate on and off commands and its greater immunity to interference, would be preferable.

Other possibilities include phone service, which is provided to a large percentage of households. It has been suggested that phone lines be used as a one- or two-way medium for electric load management signals. There is no question that this would be technically feasible, but the interfacing of the phone and load management systems may turn out to be more expensive than some of the alternative control methods. There is also the problem of incomplete coverage of the electrical load and the questions of which utility should have priority over the lines. These problems make it unlikely that phone lines will be used for load management purposes in the foreseeable future. The same applies to the possible use of the one-way cable systems, which are now used for the transmission of TV and FM signals. Two-way cable television (CATV) systems would offer a tremendous range of possibilities, including automatic meter reading, but it is clear that the practical implementation of the so-called "wired city" idea still is far in the future.

Finally, very little energy is consumed in the operation of load management systems. Control clocks use about 3 watts per clock continuously, i.e., about 60 kW in a system using 20,000 clocks. Ripple control signals are injected at about 3 percent of the line voltage, i.e., at about 0.1 percent of the system power. The transmission of ripple control signals thus requires about 1 kW for each MW of load. Contrary to the clocks, this power is, however, used only during the actual transmission of the control signals. In radio control, the power requirements are even smaller than in the other control methods.

## FEA'S UTILITIES CONSERVATION PROGRAM

The Federal Energy Administration is attempting to improve energy efficiency in the utilities sector by cultivating the mutual interests of utilities, regulatory authorities, consumers, and environmentalists in this area. On the one hand, we must insure the capability of utilities to supply adequate electricity to the Nation at reasonable prices. On the other hand, we must conserve energy by minimizing the inefficiencies and wastages, which occur not only in the consumption of generator fuels, but also in the ultimate consumption of electricity itself. Although in some limited respects, these two objectives may conflict, we believe that this is not generally the case and that energy conservation programs such as load management will not complicate, but actually enhance, the financial situation of electric utilities.

Cultivating this overlap of interests, FEA conservation programs for electric utilities will emphasize field demonstrations, regulatory intervention, and encouragement of regulators, utility leaders, and consumers to adopt energy conservation/load management practices. Assuming sustained mutual commitment to positive action, such a voluntary program could achieve the following electric power objectives by 1985:

1. Improve capacity factor (average/capacity) and load factor (average/peak) from the present 49 percent

and 62 percent respectively, to 57 percent and 60 percent;

2. Expand coal and nuclear generation from the present 60 percent of kilowatt-hour output to 67 percent;

3. Reduce the use of oil in electric power generation by at least 1 million barrels per day, relative to business-as-usual projections;

4. Increase end-use efficiency of electricity consumption by at least 10 percent;

5. Encourage end-use fuel switching to efficient electricity applications.

In the case of gas utilities, national energy conservation goals for the period 1976-85 are not so complex, although the need is more pressing:

1. Improve end-use efficiency by at least 10 percent;

2. Reduce nonessential consumption by eliminating 80 percent of outdoor lighting and installing electronic igniters in lieu of pilot lights on 46 percent of gas furnaces, ranges, and water heaters;

3. Implement emergency curtailment plans as necessary to cope with near-term supply shortfalls.

## OFFICE OF UTILITIES PROGRAM

The Office of Utilities Programs within Energy Conservation and Environment has the primary responsibility for developing, managing, and coordinating all energy conservation programs for electric and gas utilities. The office is divided into two suboffices, one of which is the Office of Utilities Policy and Demonstrations. Its mission is to gather facts and formulate recommendations affecting the energy efficiency of the conversion, transmission, and distribution processes as well as end-use consumption practices.

The office has also begun to enter into cooperative agreements with agencies of State and/or local governments to support "demand management" projects for electric utilities. These demonstration projects highlight certain options available to regulatory authorities and individual utilities to conserve energy in the generation, transmission, local distribution and end-use of electricity. For example:

1. The Arizona Fuel and Energy Office is developing and testing innovative rate forms to give the residential consumer an incentive to defer electrical demand to off-peak periods. These rates would be based on time-of-day pricing and a summer/winter pricing differential. Load scheduling systems and hardware will be utilized to assist the customer in managing his electrical demand.

2. The Arkansas Public Service Commission will monitor the consumption practices of residential, commercial, and industrial customers in response to unannounced changes in utility rate schedules, such as flattening the (historical) declining block rates, time-of-day rates, and an increased summer/winter differential.

3. Investigations by the Los Angeles Department of Water and Power into alternative rate structures that may be superior to those currently in use in the U.S. will quantify the effects of peak-load pricing on residential, commercial, and industrial customers; the administrative and technical feasibility of alternative rate structures; and adaptability of this system to utility systems in different geographic locations.

4. The Connecticut Public Utilities Commission will examine residential consumer acceptance of peak-load pricing. Such pricing will reflect the long-run incremental costs of producing electricity during heavy demand.

5. A study conducted by the New Jersey State Energy Office will measure the economic reaction of residential customers to a time-of-day rate structure. The consumption behaviors of three groups of customers will be investigated:

- residential units with electric water heaters;
- residential units without electric water heaters;
- residential units with electric water and space heaters.

The Office will also conduct a pilot demonstration of an automatic remote meter-reading and control system to shed electrical loads during peak demand.

6. The Public Utility Commission of Ohio will randomly select 100 residential units and use multichannel recording devices to establish demand patterns. Data will be collected under conventional electric rate schedules, time-of-day metering, and under remote control of electric water heaters, space heaters, and air conditioners. Computer models will be developed to estimate the probable effects of various load management options on the utility system's load.

7. A utility demonstration project in Vermont will test rate designs incorporating cost incentives, disincentives, and physical controls, which affect the time and magnitude of electric energy (consumption) requirements. The Green Mountain Power Company will design rates and install equipment to test the benefit/cost relationships, contribution to system peak, and feasibility of off-peak and interruptible heating systems in comparison to conventional electric residential heating systems.

The other suboffice, the Office of Utilities Policy Implementation, is responsible for having appropriate conservation policies and practices adopted by utilities, including practices based on the outcome of the conservation demonstration conducted by the Policy and Demonstration Office. A program sponsored by Policy implementation that has recently gained notoriety is "Utilities Conservation Action Now" (UCAN). UCAN is a voluntary, yet structured, campaign to insure open, two-way communication in the development and implementation of national energy policy, to elicit "affirmative energy action" commitments from key institutions, and to provide national coordination and other support for these individual institutional efforts. Institutions to be directly involved in this program include the 100-150 largest gas and electric utilities, State and local regulatory commissions, national consumer and environmental groups, and major utility trade organizations. The involvement of these diverse groups should insure that UCAN activities make sense in light of all pertinent needs, constraints, and opportunities.

UCAN's challenge is not directed solely at the American utilities, which have traditionally provided safe, reliable service at reasonable rates. Rather, it is to all interest groups whose activities bear upon utilities matters and who have the potential of making positive contributions to the solution of the Nation's energy problems, to cooperatively begin the work of building a better energy future. The challenge to the Federal Energy Administration, as national UCAN coordinator, is to stimulate mutual education through two-way communication; to provide supporting policy guidance and materials; to reconcile fundamental differences when possible; and, perhaps most importantly, to insure that UCAN action plans are responsive to regional and local needs, while serving the nationa' interest.

The UCAN campaign will be an ongoing FEA activity consisting of the following program elements:

1. Information materials and workshops designed to familiarize participants with policies, practices, and available technologies supportive of national energy goals. These will be handled on a regional basis.

2. Development and adoption, by all participating utilities and other groups, of UCAN action plans featuring organizational commitments to specific energy-efficiency measures, quantified objectives, and implementation schedules.

3. Periodic and special reporting to FEA by all participating organizations of progress in implementing the Action Plans, together with requests for FEA support as necessary.

4. FEA intervention in State and local regulatory hearings to clearly establish national energy policy with respect to utilities and to advocate specific actions on the part of utilities and/or commissions to achieve national energy policy goals.

5. Ongoing national and regional publicity of UCAN purpose and progress, including degree of support received from utilities, regulatory commissions, and periodic Federal awards for exceptional performance.

### *Related Activities*

Utilities conservation policy in FEA is directed at the development of guidelines, incentives, and regulations to improve the utilization of generating equipment, promote higher conversion and transmission efficiencies, and moderate future growth in demand. In cooperation with FEA, several other government agencies are also actively pursuing utility-related research: The Energy Research and Development Administration, the Federal Power Commission, and the National Science Foundation are just a few.

Paralleling government-sponsored research, several State public utility commissions have taken the lead in major load management studies. PUC's in New York, California, and other States have begun holding generic meetings on the design of rate structures with emphasis on load management. Moreover, the Wisconsin PUC has directed a major utility to implement full peak-load pricing on specified existing industry and commercial accounts. Finally, the Edison Electric Institute, in joint with EPRI, is examining rate design and load management techniques to lessen electric system peak demand growth and, thus, contribute toward the conservation of capital.

While some aspects of the problems examined in the above studies may be unique to the utility system examined, the studies should indicate potential solutions that, once modified, could be applied on a nationwide basis to solve common problems experienced by utilities.

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# POLICIES TO REDUCE TRANSPORTATION FUEL USE

Eric Hirst, Ph.D.[1]

## *Abstract*

*This paper reviews historical trends in passenger traffic and energy use since 1950. Overall, transportation fuel use grew from 8.9 QBtu in 1950 to 18.3 QBtu in 1974, with an average annual growth rate of 3.0 percent. Energy use grew more rapidly than did traffic during this period because of shifts from energy-efficient to energy-intensive modes and increases in energy intensiveness for most modes (due both to declining load factors and reduced vehicle fuel economy).*

*A number of alternatives exist for reducing transportation fuel use. This paper discusses the energy savings possible due to expanded and improved urban mass transit services, increases in new-car fuel economy, increases in the price of gasoline, and increases in commute-auto occupancy (carpooling). Expanded mass transit is likely to save only small quantities of energy during the next 5 to 10 years, primarily because of the very low fraction of urban passenger travel now carried by transit. Legislating increases in new-car fuel economy and/or higher gasoline prices can save substantial quantities of fuel in both the short and long run. Policies to induce higher auto occupancy during peak periods are unlikely to save much energy in the short term both because of their political infeasibility and individual reluctance to change habits.*

## *Introduction*

Between the end of World War II and 1972, transportation fuel use grew steadily and rapidly because of increases in both passenger and freight traffic, shifts towards the use of less energy-efficient modes, and declines in energy efficiency for individual modes (ref. 1). However, since 1972 a number of forces have emerged that may significantly alter these trends in the future.

These forces include the Arab oil embargo and the subsequent sharply higher prices for gasoline. After nearly two decades of falling "real" prices, the price of gasoline increased 26 percent between 1972 and 1974; since then prices have risen even higher (ref. 2). Because of these higher gasoline prices, the percentage of personal consumption expenditures devoted to gasoline increased 23 percent between 1972 and 1974 (to $36 billion in 1974). Prices of new automobiles are also rising rapidly—up from an average of $3,700 in 1972 to $4,400 in 1974 (ref. 3)—although they are rising no faster than the overall Consumer Price Index.

In addition to these economic forces, a number of institutional changes are underway or under serious consideration. The National Mass Transportation Assistance Act of 1974 authorizes the expenditure of nearly $12 billion during the 1975-1980 period. Unlike previous Federal programs for mass transit, the 1974 legislation authorizes operating, as well as capital, grants for transit systems. The automobile industry under pressure from the Federal Government agreed to improve new-car fuel economy 40 percent between 1974 and 1980 (from about 14 mpg to 20 mpg); the Government is considering a number of measures to require these and greater fuel economy increases. Modifications to the Federal Highway Trust Fund allow funds to be used for mass transit improvements and to encourage carpooling; several communities are beginning to institute significant carpool programs.

The extent to which these and other new forces will operate on traditional patterns of personal travel and land use to change the energy intensiveness and energy use of our transportation system is the subject of this paper. It examines the period 1950-1972 with respect to personal travel and its energy use, reviews the relative energy efficiencies of different urban and intercity passenger systems, discusses several policies for reducing transportation fuel use, and compares the energy savings likely with each of these policies in 1980 and 1985.

Measures to reduce transportation fuel use can be grouped into three generic classes, as shown in table 1. The policies discussed here include all three classes:

Policy . . . . . . . . . . . . . . . Improve mass transit
Class . . . . . . . . . . . . Shift to more efficient modes

Policy . . . . . . . . . . . . . . . . Increase carpooling
Class . . . . . . . . . . . . . . . . Increase load factors

Policy . . . . . . . . . . . . . . . . Raise gasoline prices
Class . . . . . . . . . . . . . . . . . . . . . . . . All classes

Policy . . . . . . . . . . . Impose new-car mpg standards
Class . . . . . . . . . . . . Improve technical efficiency

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Table 1. Transportation conservation measures

| |
|---|
| Use existing transportation systems more efficiently: |
| Shift to more efficient modes |
| Increase load factors |
| Improve operational and usage characteristics. |
| Improve technical efficiency of individual modes. |
| Reduce demand. |

These four policies were selected for discussion because they are among the most important and most widely discussed, and because analyses exist with which to evaluate their effectiveness. However, several other important options exist, such as stricter enforcement of the 55-mph speed limit, wider adoption of right-turn-on-red, better urban traffic control systems, and a host of changes related to air traffic and freight traffic.

This paper concludes that, in the short run at least, significant passenger transportation energy savings can be achieved only by improving new-car fuel economy. Behavioral changes (greater use of mass transit and carpooling) are surprisingly insensitive to purely economic forces unless they are so strong as to be politically infeasible. This suggests the need for more and better programs to encourage people to change their attitudes and tastes towards energy use and personal transportation.

### *Historical Trends in Passenger Travel and Energy Use*

Total transportation fuel use grew from 8.9 QBtu ($10^{15}$ Btu) in 1950 to 18.3 QBtu in 1974 (refs. 4,5) with an average annual growth rate of 3.0 percent. Between the mid-1960's and 1972, the growth rate was much higher, at 4.7 percent a year. However, transportation fuel use increased only 3.3 percent between 1972 and 1973 and actually declined 3.2 percent between 1973 and 1974 (ref. 4). The 1974 decline was due to a combination of sharply higher fuel prices, spot shortages during the summer, the Arab oil embargo that winter, and the 2 percent decline in GNP between 1973 and 1974.

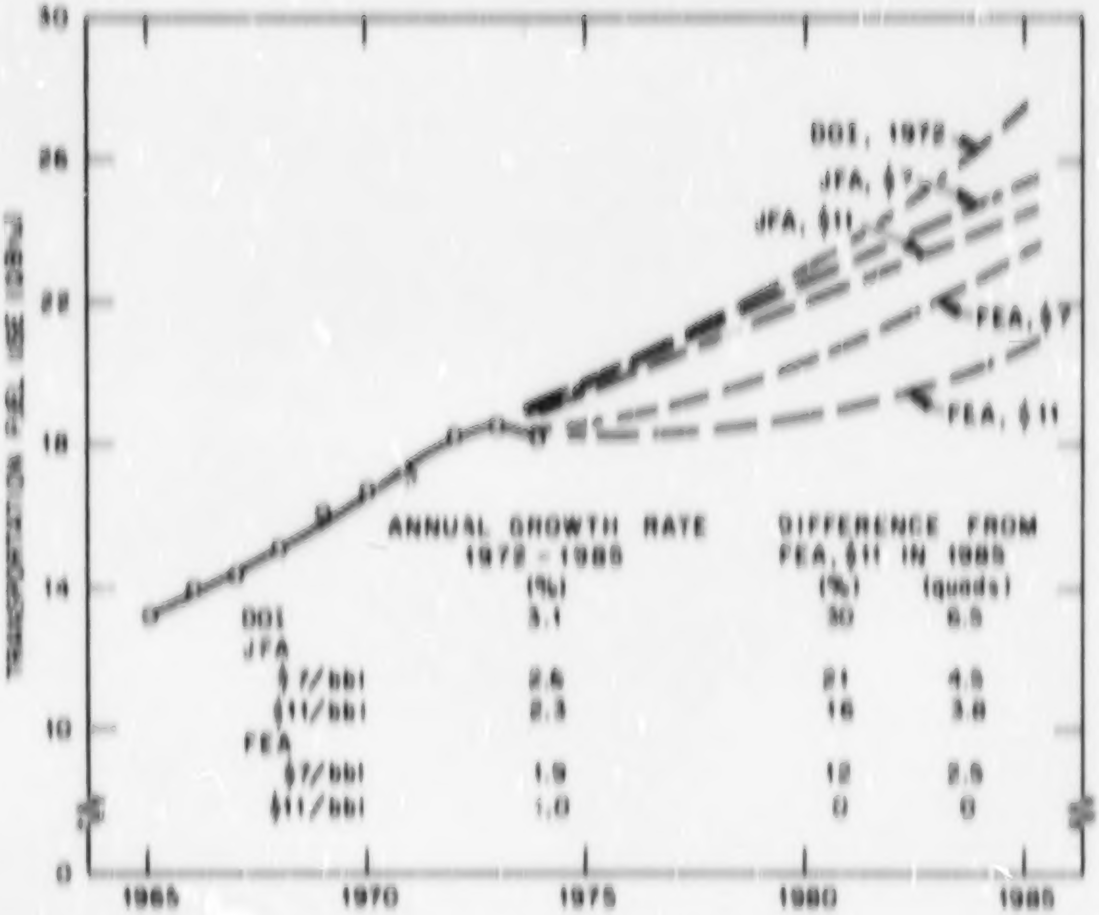
Figure 1 shows actual transportation fuel use from 1965 through 1974 and projections to 1985 from three different sources. The Department of the Interior (ref. 6) projection was prepared in 1972—long before recent oil price increases. The other two sets of forecasts, by Jack Faucett Associates (ref. 7) and the Federal Energy Administration (ref. 8), were prepared during the summer of 1974 as part of the Project Independence effort. These forecasts used crude oil prices (in 1973 dollars) of $7 and $11/bbl. The variation among forecasts is considerable. The Interior forecast is much higher than the others, presumably because it assumes the low oil prices of the 1960's; its growth is equal to the long-run growth rate over the past two decades. The other four forecasts show growth rates far below the historical trend. If these latter forecasts prove correct, considerable fuel savings will be achieved in the transportation sector because of fuel price increases alone.

Intercity passenger traffic is carried primarily by automobile and, to a lesser extent, by airplane, bus, and train (ref. 1). The variation in energy intensiveness (EI) among these modes (table 2) is considerable. Buses and trains are the most efficient modes, followed by autos and airplanes. In 1972, EI for airplanes was five times higher than for buses. However, airplanes were the fastest mode and automobiles are the most convenient in terms of schedules and routes.

Between 1950 and 1972, the fraction of intercity passenger traffic carried by airplane climbed rapidly at the expense of trains and buses. Energy consumption rose 192 percent as a result of a 156 percent growth in traffic and a 14 percent increase in overall EI (refs. 1,8,9). This increase in EI was due to increases in EI for individual modes and to the shift from buses and trains to airplanes.

Urban passenger traffic is carried almost exclusively by car, with only a small and declining fraction carried by mass transit (buses and electric transit) (ref. 1). As table 2 shows, mass transit is two to three times as energy-efficient as autos are (refs. 9-11). Urban EI values are double comparable intercity values because of poorer vehicle performance (fewer miles/gallon) and poorer utilization (fewer passengers/vehicle) in cities.

Between 1950 and 1972, the fraction of urban passenger traffic carried by cars steadily increased. Energy use grew 210 percent, caused by a 161 percent rise in



|  | ANNUAL GROWTH RATE 1972 - 1985 (%) | DIFFERENCE FROM FEA, $11 IN 1985 (%) | DIFFERENCE FROM FEA, $11 IN 1985 (quads) |
|---|---|---|---|
| DOI | 3.1 | 30 | 6.5 |
| JFA |  |  |  |
| $7/bbl | 2.6 | 21 | 4.5 |
| $11/bbl | 2.3 | 16 | 3.8 |
| FEA |  |  |  |
| $7/bbl | 1.9 | 12 | 2.5 |
| $11/bbl | 1.0 | 0 | 0 |

Figure 1. Total transportation fuel use and forecasts.

traffic and a 22 percent increase in EI (refs. 1,9-11). Increased EI was due to higher individual modal EI and to the shift from mass transit to automobiles.

Figure 2 shows how EI for urban modes increased between 1950 and 1973. Similar increases in energy intensiveness occurred for the intercity modes, except for railroads.

Figure 3 shows the distribution of transportation fuel by mode, market, and purpose for 1972 (ref. 7). Passenger travel dominates the fuel use budget, accounting for more than two-thirds of the total. The automobile (defined in ref. 7 to include cars, motorcycles, and personal use of trucks) uses 60 percent of the fuel. Urban transit accounts for only 0.5 percent of the fuel use. Intercity bus and rail passenger service also use less than 1 percent of the fuel.

Table 2. Energy intensiveness of passenger modes, 1972

| Mode | EI Btu/PM[a] | Mode | EI Btu/PM[a] |
|---|---|---|---|
| Intercity | | Urban | |
| Airline | 7,200 | | |
| Automobile | 3,100 | Automobile | 6,700 |
| Rail | 2,700 | Rail transit | 2,600 |
| Bus | 1,600 | Bus transit | 3,000 |

[a] EI = energy intensiveness; PM = passenger-miles.

Source: Updates using data sources and methodologies discussed in reference 1.

Trucks are the second most important energy-using mode. However, trucks represent a much more heterogeneous mode than do automobiles. The 18 percent figure shown for trucks includes both local and intercity truck freight traffic.

The third most important energy-using mode is the airplane, accounting for 8 percent of the fuel. Nontruck freight modes use 8 percent and the military uses another 5 percent of the transportation fuel budget.

### *Improved Transit*

Although transit is considerably more energy-efficient than automobiles are, transit presently carries such a small fraction of total urban passenger travel (2.5 percent in 1973) that its short-term potential contribution to energy conservation is slight. The data shown in table 3 from three recent transit demonstrations (refs. 12,13) suggest that the energy impacts of transit fare reductions and service improvements (expanded area coverage, reduced headways) are almost negligible.

There are several reasons for the slight energy impacts shown in table 3. First, transit accounts for a tiny fraction of urban travel and an even smaller fraction of the urban travel energy budget. Thus sizable increases in transit traffic will have only slight impacts on total urban traffic and energy use. Second, while reduced fares and improved service will increase ridership, the experience cited above suggests that less than half the increase comes from former automobile drivers. The remainder are auto passengers, walkers, users of other transit systems, and people who formerly stayed home. Only shifts from auto driver to transit reduce overall energy use. Third, expanded route coverage and reduced headways lower system load factors; this increases EI and energy use. Fourth, automobiles are often used to gain access to transit systems; this auto energy use must be subtracted from the energy savings due to the shift from auto to transit.

Figure 4 shows the sources of increased ridership (refs. 13,14) due to the improvements in Atlanta's bus system, summarized in table 3. In 1972, fares were reduced from $.40 to $.15 and a number of service improvements were instituted: some lines were extended, some were revised, new routes were established, and headways were reduced overall. The net impact of these changes was an increase in annual coverage from 19 to 22 million bus-miles.

Bus patronage increased 28 percent due to the fare reduction and service improvements. Reducing fares increased load factors by increasing ridership with no increase in bus-miles. Service improvements, on the other hand, lowered load factors because ridership—in Atlanta, at least—increased more slowly than did bus-miles. Overall, the combination of reduced fares and increased service raised load factors slightly. Because more than half of the new riders were not formerly auto drivers, the fuel savings—8,300 gal/day—is slight.

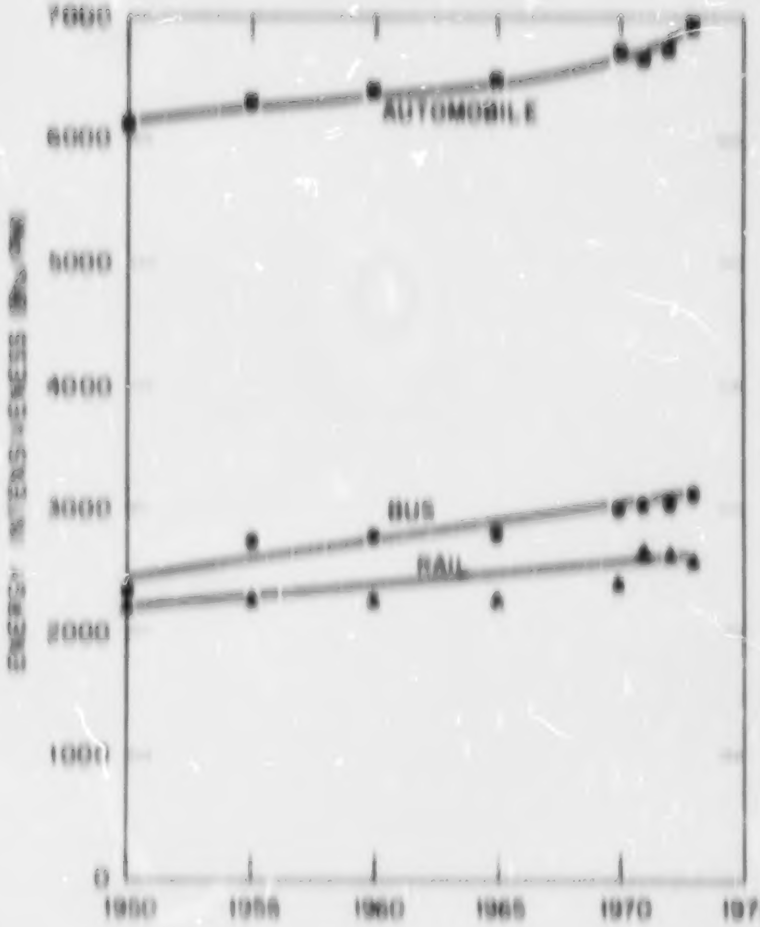


Figure 2. Urban travel modes energy intensiveness, 1950-1973.

The major conclusion from table 3 and figure 4 is that transit improvements alone offer little hope of large energy savings. Improving mass transit (time, costs, service characteristics) can save energy only if the increased transit ridership comes primarily from automobile drivers. Increasing transit patronage by attracting people from nonauto modes (other transit systems, walking, bicycling, previously foregone travel) will probably increase urban passenger energy use. Thus saving energy via increased transit requires both the "carrot" and the "stick." The carrot is to induce people to travel via transit and the stick is to force people out of their cars.

Even if transit improvements and auto disincentives are effective, transit is unlikely to provide substantial energy savings during the next decade. The potential energy savings are limited by the small size of the present transit plant and the small fraction of urban travel moved by transit. Doubling the percentage of urban travel carried by transit from 2.5 percent in 1973 to 5.0 percent in 1980 would require 100,000 new buses during this 7-year period, compared with the 1973 fleet of 46,000 buses (ref. 10).

Assuming that funds can be found to finance the purchase of these buses; that drivers, mechanics, and managers can be trained during this period; that ridership will increase; and that the new riders will come from automobiles; the energy savings for 1980 are equivalent to 62,000 bbl/day of crude oil (refs. 9,11). If the

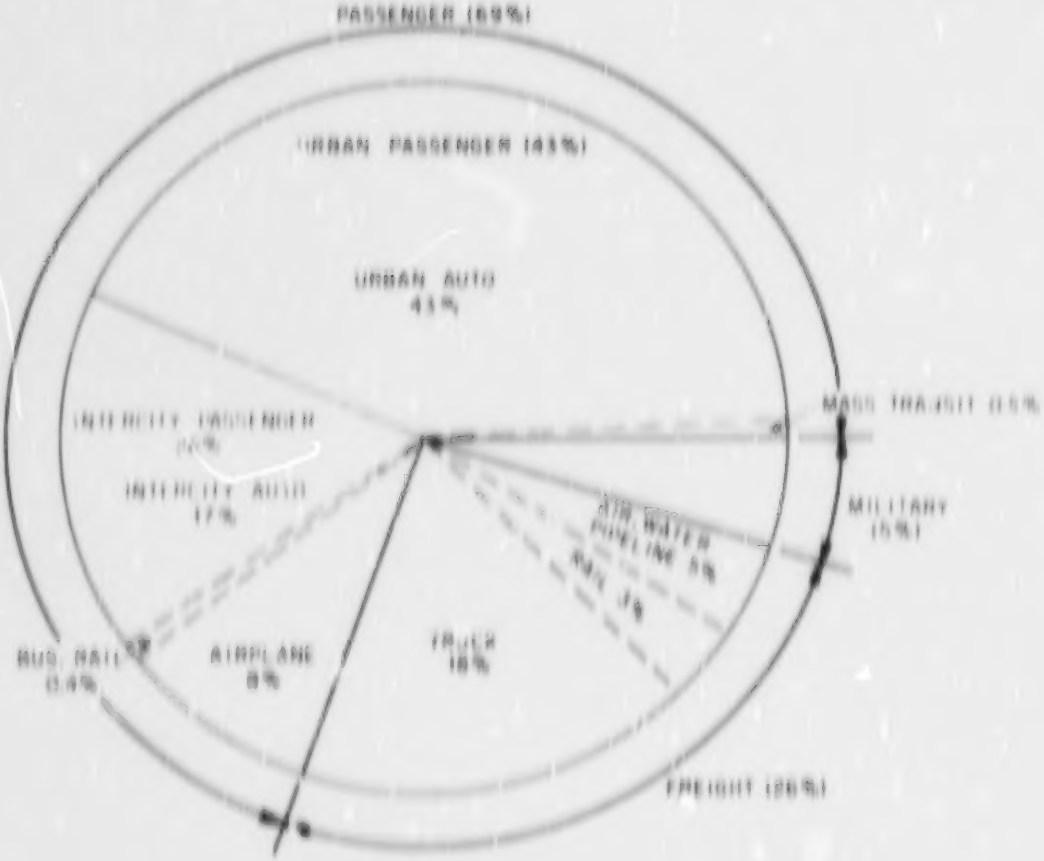


**Figure 3. Distribution of transportation fuel use, 1972.**

percentage of urban passenger travel carried by transit increases to 7.5 percent in 1985 (a tripling of its 1973 market share), the national energy savings would be equivalent to 122,000 bbl/day of crude. As shown later, the energy savings possible by increasing transit travel are small relative to the savings possible with other transportation measures.

Although the short-term energy conservation potential of increased mass transit is slight, this does not mean that transit improvement programs should be abandoned. Changes in urban travel patterns are likely to require at least a decade because of long lags associated with changes in land use patterns, auto ownership, and individual attitudes towards public transportation. Thus, unless transit improvement projects are undertaken now, the long-term potential benefits of transit will never be realized. Also, transit offers other benefits besides reduced energy use: less congestion during peak periods, fewer traffic fatalities, and increased mobility for those with limited access to autos. Finally, combining transit improvements with auto disincentives (such as the gasoline tax increase discussed later) provides a transportation alternative to those dislodged from their automobiles.

### *Carpooling*

The average automobile load factor for urban work trips is presently only 1.4 passenger-miles/vehicle-mile (PM/VM) (ref. 11). There is thus an enormous energy conservation potential in the empty automobile seats traveling during the daily peak hours. Increasing this

Table 3. Energy conservation impacts of transit improvements

| Strategy | Estimated savings[a] |
|---|---|
| Regional bus - Atlanta | |
| 40¢ to 15¢ fare | 9,000 gal/day |
| 19 to 22 million bus-miles/year | (0.5 percent) |
| 28 percent increase in ridership | |
| Corridor service, bus - D.C. | |
| Shirley highway (I-95) | |
| 11-mile busway in median | |
| 1,900 to 11,500 pass/day in 5 years | 3,000 gal/day |
| 40 percent of riders were auto drivers | (0.1 percent) |
| 30 percent of riders get to bus by car | |
| Corridor service, rail - Philadelphia | |
| Lindenwold line | |
| 30,000 riders/day carried by line | -450 gal/day |
| 28 percent of riders were auto drivers | (0 percent) |
| 90 percent of riders get to line by car | |

[a] Figures in parentheses are percents of regional transportation fuel use saved.

Source: References 12 and 13.

load factor from 1.2 to 1.5 PM/VM would save 440,000 bbl/day of crude oil in 1980. However, serious questions exist concerning the methods available to induce greater auto occupancy and the effectiveness of these methods.

Cambridge Systematics, Inc. (CSI) is analyzing a variety of carpool promotion options (ref. 18) using a modification of their disaggregate travel demand models that estimate auto ownership and changes in work trip and nonwork travel in response to these policies. Their model is applied to Washington, D.C., using data collected during the D.C. 1968 Home Interview Travel Survey. CSI is examining a number of carpool alternatives related to the cost and supply of parking, costs of auto travel (tolls, gasoline taxes, carpool subsidies), direct regulation of urban travel (auto-free zones, gasoline rationing), and employer incentives.

Their model's preliminary outputs for a number of such alternatives are shown in table 4. These results are short-run impacts; that is, they do not include long-run changes in auto ownership that will occur because of these policies.

Table 4 shows that both parking incentives for carpools and major increases in parking costs substantially reduce the amount of solo driving and increase both carpooling and mass transit use. However, these reductions in commuting travel are partially offset by increases in nonwork auto travel. These increases arise because more automobiles are available for nonwork travel. In the long run, many of these "extra" cars will probably not be replaced; thus the long-run energy savings are likely to be larger than the short-run savings.

As an example, consider the predicted impacts of an increase in areawide parking costs of $3/day. The parking surcharge reduces work-trip travel by 10 percent, a 3.9 percent reduction in overall urban travel. However, the induced nonwork travel amounts to 1.4 percent of

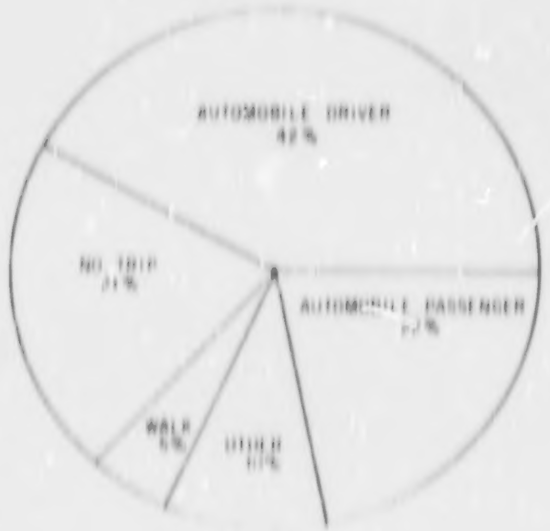


Figure 4. Previous travel modes for new Atlanta bus riders.

the urban total. The net impact of the $3/day surcharge, therefore, is only a 2.5 percent reduction in urban auto travel.

The percentage reduction in fuel use is less than the percentage reduction in travel because of fuel penalties associated with increased trip circuity, extra weight for carpooling, and increased cold-starts for nonwork trips. Thus, urban auto fuel use is cut by only 2.1 percent compared with the 2.5 percent reduction in travel due to the parking surcharge. This is equivalent to a national fuel savings of 60,000 bbl/day of crude oil in 1980.

Let us assume that, in the long run, only half the induced short-run nonwork auto travel occurs. Then, if long-run equilibrium is achieved in 1985, the 3.9 percent reduction in urban travel due to increased carpooling coupled with the 0.7 percent increase in nonwork travel reduces urban travel by 3.2 percent. This amounts to a 2.7 percent reduction in urban auto fuel use, equivalent to 105,000 bbl/day of crude oil in 1985.

These results—fuel savings of 2.1 percent and 2.7 percent in 1980 and 1985 respectively—show a remarkable insensitivity on the part of commuters to changes in travel costs. Adding $3/day to the base cost of parking increases the overall cost of commuting by 100 to 200 percent. The response to this enormous change in cost is only a 10 percent reduction in work-trip travel.

As discussed later, policies that affect all automobile travel (both work and nonwork) are likely to be more effective in saving energy for two reasons. First, work trips account for only a third of all auto travel (although they account for about 40 percent of all auto gasoline use). Second, nonwork trips are likely to be more discretionary than are work trips and therefore more sensitive to changes in dollar and time cost.

The results of this ongoing CSI study should be interpreted cautiously. The data used to construct the model are from 1968—a time when fuel prices were low, Washington's transit service was poor and deteriorating, Americans loved their autos, and incomes were rising steadily. Thus the data are from an era in which our attitudes and behavior strongly favored automobile ownership and use. Also, models such as that developed by CSI capture the major demographic and economic variables affecting travel decisions but they cannot explicitly model changes in attitudes. To the extent that attitudes towards energy use, carpooling, and automobiles have changed since 1968, the model's results are in error. Finally, CSI's model evaluates only the short-run impacts of policy changes. As households adjust their auto ownership and home location in response to these policies, the impacts of these policies may increase.

### *Gasoline Taxes*

One policy that is often discussed but rarely embraced is an increase in the Federal tax on gasoline, currently at $.04/gallon. Those favoring an increase argue that it would be an effective way to reduce gasoline use, that it allows maximum consumer choice (in terms of changes in both vehicle use and vehicle ownership), and that it is simple and inexpensive to administer. Opponents argue that its economic burden on low-income families (especially those in which the breadwinner must commute by car) would be intolerable, that consumer demand for gasoline is insensitive to price changes, and that further increases in gasoline prices would adversely affect the economic recovery.

The Office of Energy Systems in the Federal Energy Administration (FEA) developed a simple econometric model for estimating changes in automobile travel, fuel economy, and ownership in response to changes in gasoline prices (and also to exogenous changes in new car fuel economy) (ref. 16). The model contains three behavioral equations that estimate annual demands for automobile travel, new car sales, and new car fuel economy as functions of income, unemployment, gasoline price, and the average age of the automobile stock.

Automobile gasoline use from 1965 to 1975 and several projections to 1985 (using the FEA model) are shown in figure 5. The gasoline tax in these simulations is expressed as a constant percentage of the base price to

Table 4. Energy impacts of carpooling policies in Washington, D.C.

| Policy | Percent change in work trip mode shares | | | Percent change in VMT (miles) | | | Percent change in fuel consumption |
|---|---|---|---|---|---|---|---|
| | Drive alone | Carpool | Transit | Work | Nonwork | Total | |
| Base values excluding weekend travel) | 52.9% | 25.4% | 14.5% | 10.4 (mi) | 16.7 (mi) | 27.1 (mi) | 2.58 gal/day |
| Parking incentives[a] | -10.69 | 22.05 | 0.40 | -3.37 | 1.02 | -0.64 | -0.55 |
| Parking incentives & parking costs[a] | -22.27 | 43.02 | 4.55 | -9.82 | 2.50 | -2.24 | -1.93 |
| Base parking cost + $1 (areawide) | -5.07 | 4.50 | 10.61 | -3.27 | 0.71 | -0.81 | -0.68 |
| Base parking cost + $3 (areawide) | -15.61 | 13.93 | 32.57 | -10.20 | 7.29 | -2.49 | -2.07 |
| Base parking cost + $3 (CBD only) | -6.52 | 2.97 | 17.83 | -4.04 | 1.04 | -0.92 | -0.78 |
| Carpool subsidy, 5¢/PM | -4.04 | 11.31 | -5.06 | -2.47 | 0.43 | -0.60 | -0.50 |

[a] Parking incentives refer to the restriction that "close-in" parking spaces are reserved for carpoolers. Parking incentives and parking costs add a $2/day parking charge for solo drivers.

Source: Reference 15.

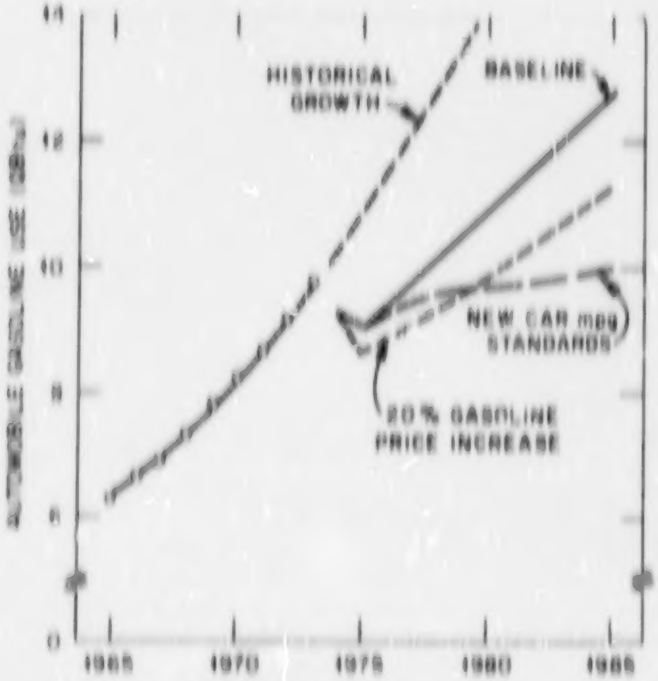


Figure 5. Automobile gasoline use forecasts to 1985.

avoid problems with inflation (in which a current dollar tax becomes weaker each succeeding year); the tax (20 percent) is imposed in 1976 and remains in effect during the 10-year simulation.

Between 1965 and 1973, automobile gasoline use increased at an average annual rate of 5.6 percent. The top curve in figure 5 shows the continuation of this historical trend. The curve marked "baseline" represents the output from the FEA model assuming that the "real" price of gasoline remains constant at its assumed 1975 level ($.55/gallon) and that no new policies are imposed that would affect auto ownership and use. The baseline curve shows that recent increases in gasoline prices are expected to substantially reduce growth in gasoline use: from 5.6 percent to 3.5 percent annually. Increasing gasoline prices by an additional 20 percent further slows the annual growth rate to 2.7 percent. Relative to the baseline fuel use, the 20 percent tax saves the equivalent of 484,000 bbl/day of crude oil in 1980 and 700,000 bbl/day in 1985. These fuel savings are nearly an order of magnitude larger than those due to programs that increase carpooling or mass transit use.

The short-run price elasticity of demand for gasoline implied by the FEA model is -0.21; the long-run elasticity is -0.72 (ref. 16). These elasticities are in good agreement with those derived in other studies (ref. 17).

Figure 6 shows changes in new car fuel economy predicted by the model. In the baseline, fuel economy improves from 14 mpg in 1974 to 15 mpg in 1978 and then drops back to about 14.3 mpg during the next 7 years. This decline in fuel economy is due to the assumed rise in personal incomes: as incomes grow, the price of gasoline becomes a less important determinant of new-car purchase decisions. The 20 percent gasoline tax simulated here causes a sharp increase in new-car fuel economy to 17 mpg in 1978. Then fuel economy drops to an average of 16.2 mpg during the next 7 years.

The curves of figures 5 and 6 show that the major response mechanism to higher gasoline prices is an increase in new-car fuel economy rather than a decline in auto travel. During the first year, however, approximately three-fourths of the change in gasoline use is due to reduced driving and only one-fourth is due to improvements in fuel economy (ref. 17). Auto travel is reduced

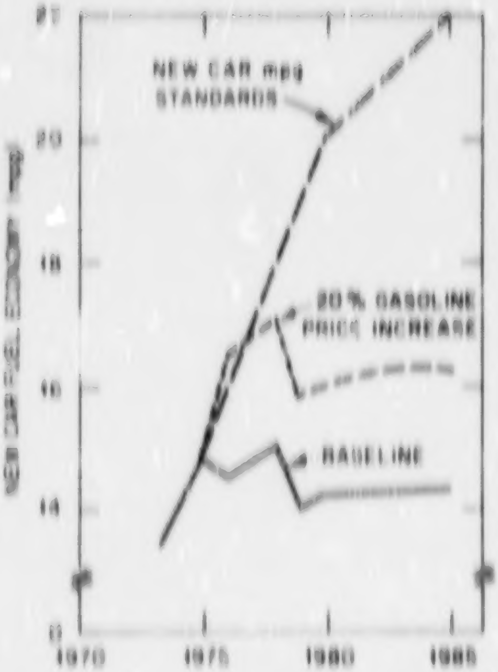


Figure 6. New car fuel economy forecasts to 1985.

4 percent in 1975 and 1976, 2 percent in 1980, and 1 percent in 1985 because of the 20 percent increase in gasoline price. Thus, as more and more new cars (purchased after the gasoline price increase) enter the fleet, changes in auto travel become negligible.

*New Car Fuel Economy Standards*

The FEA model (ref. 16) can also be used to evaluate the impacts of improvements in new car fuel economy. Figure 5 shows the model's predictions of automobile gasoline use when new-car standards are imposed that require average new-car fuel economy to increase from 14 mpg in 1974 to 20 mpg in 1980 and to 22 mpg in 1985. Figure 6 shows the imposed fuel economy schedule.

The gasoline savings due to these improvements in new-car fuel economy are substantial—even higher than those due to the 20 percent gasoline price increase. However, because only about 10 percent of the automobile stock is "rolled-over" each year, it takes a few years before the standards have a major impact on fuel use. The schedule simulated here yields fuel savings equivalent to 508,000 bbl/day of crude oil in 1980 and 1,327,000 bbl/day in 1985.

Because improvements in new car fuel economy reduce the cost of driving per mile, one impact of the standards is a slight increase in the amount of auto travel: 3 percent in 1980 and 5 percent in 1985.

Figures 5 and 6 show that the 20 percent increase in gasoline price initially has a stronger effect on both new-car fuel economy and auto fuel use than do the new-car fuel economy standards considered here. However, as a larger and larger fraction of the automobile stock is influenced by a stricter and stricter fuel economy standard, the savings due to the standard equal and then surpass those due to the fuel price increase: the crossover point for the policies simulated here is in 1979. These results suggest that a gasoline tax increase is a potent short-run measure for saving gasoline while new-car fuel economy standards are powerful in the long run.

Although the FEA model is an interesting and useful tool with which to analyze automobile gasoline use policies, it contains several weaknesses that must be considered in interpreting the model's outputs. The equations estimating demands for new cars and new car fuel economy are independent of automobile prices. This implicitly assumes that improvements in fuel economy will not affect vehicle prices and that automobile prices will change in the future (relative to the other explanatory variables in the model) as they have in the past. The model also assumes that a prespecified fraction of the existing automobile fleet is scrapped each year. Thus the dynamics of the new and used car markets and auto ownership are quite restricted. Finally, the model treats all automobiles as homogeneous entities; there is no market class distinction between, say, compacts and luxury cars. In spite of these deficiencies, the FEA model is probably the most useful tool available for analyzing these policy alternatives.

*Conclusions*

Table 5 summarizes the estimated energy savings for 1980 and 1985 due to the four transportation policies discussed here. Clearly, policies that directly affect automobile ownership and use (gasoline taxes and fuel economy standards) are much more effective in saving energy than are policies designed to shift travelers to energy-efficient alternatives (mass transit and carpools).

This suggests that, during the next decade at least, attention should be focused on technological means to reduce transportation fuel use. If the numbers in table 5 are approximately correct, then one concludes that

Table 5. Energy impacts of transportation conservation measures[a]

| Policy | Estimated energy savings (thousand bbl/day) 1980 | 1985 |
|---|---|---|
| Increase percentage of urban travel carried by mass transit from 2.5 percent in 1973 to 5.0 percent in 1980 and 7.5 percent in 1985. | 52 | 122 |
| Increase carpooling sufficiently to reduce work-trip auto travel by 10 percent in 1980 and 1985. | 69 | 105 |
| Increase gasoline prices by 20 percent starting in 1975. | 484 | 700 |
| Increase new car fuel economy from 14 mpg in 1974 to 20 mpg in 1980 and 22 mpg in 1985. | 568 | 1,327 |

[a] These savings are calculated relative to a baseline in which auto travel is 1.2 trillion vehicle-miles in 1980 and 1.4 trillion vehicle-miles in 1985. Urban travel accounts for 55 percent of this total; average auto fuel economy is 14 mpg for both years and 12 mpg in urban areas. Average automobile occupancy is 2.2 PM/VM and urban occupancy is 1.6 PM/VM.

behavioral changes (with respect to personal travel) are quite difficult to effect: people are extremely resistant to purely economic forces that seek to change their travel modes and extent of travel.

These results also suggest (implicitly) the need for much greater emphasis on activities that inform people about energy problems and the need for conservation and that demonstrate the attractiveness and viability of energy-efficient practices. These activities will encourage consumers to change their tastes and attitudes; changes in consumer behavior will then follow. In other words, social norms need to be modified so that people will want to carpool, will want to ride transit, and will want to own small cars—quite apart from the economic incentives to do so.

The analyses on which the above conclusions rest use techniques and data that are far from satisfactory. The models generally capture the important economic variables (e.g., prices and incomes). However, intangibles such as comfort, convenience, reliability, safety, what the neighbors think, and whatever else goes into individual decisions on how, when, and where to travel are not captured by these models. Therefore the models can predict behavioral changes in response to economic changes only when these intangibles (those variables not included in the models) do not change.

The models are generally based on data from the 1960's. To a surprising, perhaps frightening degree, the United States today is quite different from what it was 10 years ago. This is true for fuel prices and also true with respect to individual expectations for the future and attitudes towards the environment, energy conservation, and automobiles. Thus decade-old data (even when used with very good models) may yield inaccurate estimates of behavioral changes. Also, the FEA model is estimated using time-series State-level data. CRA, on the other hand, uses detailed cross-sectional data for a single city for 1 year. Because of these differences in data, the results of these two models may not be consistent with each other.

Finally, a comprehensive model with which to evaluate these policies in combination does not now exist. Therefore, it is not possible to evaluate potential synergisms among the four policies considered individually in this paper. Combinations of auto disincentives (such as an increased gasoline tax) and improvements of alternatives (carpooling, transit) are, intuitively at least, quite appealing. Such combinations are likely to maximize energy savings while minimizing adverse mobility impacts of auto disincentives.

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4 November 1975

## Session III:

## RETROFITTING OUR PRESENT-DAY ENERGY SYSTEMS

Roger S. Carlsmith*
Session Chairman

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# NEAR-TERM POTENTIAL FOR IMPROVED AUTOMOBILE FUEL ECONOMY

Karl H. Hellman, Ph.D., and John P. DeKany[1]

## *Abstract*

*There appear to be three broad vehicle-related approaches toward improving automobile fuel economy in the near term. These three approaches, which do not involve changing or modifying the type of fuel used, are: (1) retrofit programs; (2) inspection, maintenance, and repair programs; and (3) improvement of new vehicle fuel economy. All three approaches appear to be compatible with environment goals. Examples of each approach are given, and the pros and cons of each approach are discussed. Finally, some of the types of questions that must be answered before decisions as to which, if any, of the approaches should be undertaken are listed.*

## *Introduction*

This paper discusses technological potentials for improvements in automobile fuel economy that are effected by changes to the automobile itself. Therefore, nontechnological changes directed toward reduced automobile fuel consumption such as carpooling, use of mass transit, changes in driving habits, and the substitution of bicycling or walking for the most energy-intensive (short) trips are not specifically discussed, although some or all of the above approaches are candidates for use in an overall energy conservation strategy. Also, technological approaches such as highway design and traffic control for reduced fuel consumption are not considered, although approaches of this type are also obvious approaches toward reduced fuel consumption.

The automobile or Light Duty Vehicle (LDV) is the primary subject of this paper because of its visibility and the great proportion of transportation energy consumed by vehicles of this type. Much of the discussion, however, is applicable to Light Duty Trucks (LDT's) and some of the approaches are also applicable to Heavy Duty Vehicles (HDV's).

Since the automobile is the focus of this paper, the near-term time frame can be conveniently quantified to be the average lifetime of an automobile, approximately 10 years. Therefore most of the approaches considered here should be able to be implemented within 10 years. This time frame implies that the automobiles under consideration will generally be those powered by existing engine types and fuels.

There are three basic approaches toward improving the fuel economy of automobiles. Two approaches involve programs that could affect the entire fleet of automobiles. These are retrofit programs and inspection, maintenance, and repair programs. The third, improving new automobile fuel economy, involves only new automobiles.

## *Retrofit*

One approach toward improving automobile fuel economy would be a retrofit program, that is, installing fuel-saving devices or taking other measures on all or some designated fraction of the automobile fleet.

A scheme that falls in the general retrofit area but does not involve the use of add-on devices would be the dismantling or removal of existing emission control systems on automobiles. Such actions, which are called tampering by EPA, are illegal if done by dealers. We have studied this approach and have found (ref. 1) that when done by gas stations and repair shops the results are counterproductive, as shown in table 1. Since the fuel economy went down and the emissions went up, the $22.86 average cost for this tampering seems to be not cost-effective.

Retrofits that involve the incorporation of devices to improve fuel economy are more commonly considered under the heading of retrofits. These devices span the range in complexity from simple air bleeds, through carburetor replacement and gaseous fuel conversions, to complete engine retrofits. EPA has tested many such devices. Originally most were publicized as having emissions-reduction capability; now many are being touted as having fuel-consumption advantages. In the space of this paper it is not possible to discuss even a portion of the devices, but some general comments are possible.

Besides saving fuel, retrofit devices should ideally be cost-effective for the customer; that is, the cost of the device installed should be offset by the fuel savings obtainable. The cost of the device can be computed as parts plus labor and both out-of-pocket or discounted accounting can be used. The fuel savings depend on the type of automobile, the fuel economy improvement, the number of miles driven, and the fuel cost. The results of some calculations are shown on figure 1.

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Table 1. Fuel economy and emissions impact due to tampering

| Fuel economy | HC | CO | NOx |
|---|---|---|---|
| 3.5 percent loss | 39 percent increase | 90 percent increase | 63 percent increase |

If a device cost lies above the line, it cost more than the fuel savings; if below the line, less. For example, a device that improves fuel economy by 5 percent over a 15-mpg base, using 50,000 miles of operation and $0.60/gallon for fuel cost, could cost about $97. Of course, the discounted prices would be lower. What Figure 1 indicates is that relatively small improvements in fuel economy may be justified if the device cost can be made reasonable. It therefore appears that there may be potential attractiveness to retrofit devices, if they do work.

Another potential attractive aspect of a retrofit program involves the number of vehicles that can be affected. Theoretically, the whole vehicle population could be retrofitted, thereby getting the maximum savings in fuel economy as soon as the retrofits are installed.

The outlook for retrofits, however, is not altogether positive. There are several other aspects of such an approach that must be considered:

1. The emission characteristics of retrofitted vehicles must be known, and be beneficial, before a substantial program begins, so that the gains made to date in control of automobile emissions are not lost. This implies a more comprehensive evaluation of the devices than merely checking for their fuel consumption characteristics.

2. Existing experience with retrofit programs cannot be overlooked. California's retrofit program cannot be called an unqualified success, although its experience does indicate some of the more practical problems that must be faced.

3. The service industry will probably need some

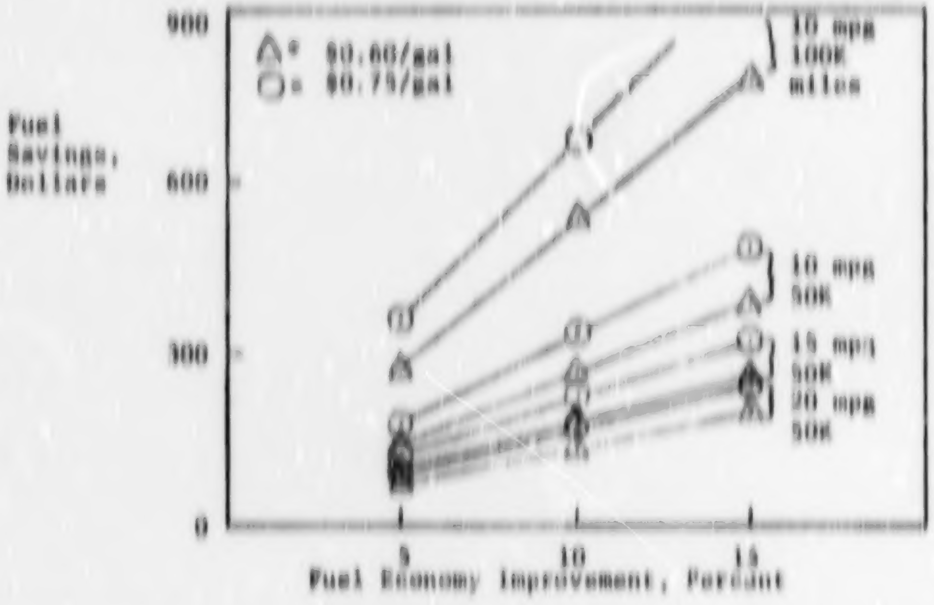

Figure 1. Fuel saving versus fuel economy improvement.

increase in capability to be able to install the devices correctly. Improper installation was found to be a problem in California.

4. Any given retrofit device will not work on all automobiles. An example is the air bleed. Air bleeds may have some beneficial effects for older, less controlled or uncontrolled automobiles, but their application to more recent automobiles that have enleanment already as a part of their emission control systems may be ineffective or even counterproductive. Therefore, if the goal is to retrofit a great percentage of the fleet, many different retrofit devices will be needed.

5. To run such programs effectively, an expensive administration, testing, and enforcement organization will probably be needed. This cost should be added to the other costs inherent in such a program to adequately assess its effectiveness.

In summary, retrofit programs for improving automobile fuel economy appear to require a great amount of planning, testing, and cost-effectiveness analysis before they can be said to be (a) viable options for reducing fuel consumption, and (b) compatible with environmental goals.

### *Inspection, Maintenance, and Repair (IMR)*

Vehicles which are not kept tuned to the manufacturer's specifications can have poorer fuel economy and emission performance than those that are tuned up. In reference 1, a limited amount of data indicates that the improvement between vehicles in the "as received" condition and tuned up exceeded 10 percent, although the more generally accepted value for an IMR program is about 7 percent, since not all vehicles will receive maintenance. Therefore, it would appear to be desirable to find some way to insure that vehicles receive the proper maintenance.

Most IMR programs contemplated to date have actually been directed toward the control of emissions from in-use vehicles. These programs usually are part of the overall program of a State to insure that ambient air quality requirements are met. Such programs involve the periodic testing of automobiles, usually on a yearly basis, and the identification of those vehicles which are not within specified requirements and which must be fixed so that they will pass.

The advantages of IMR programs are:

1. All vehicles are affected. The benefits from such programs can therefore be realized in a relatively short time.

2. Compared to retrofit programs, there is no expense involved for devices.

3. Since most programs are emission-control oriented, the environmental effects appear to be beneficial.

As is the case with retrofits, there are also some potential disadvantages to IMR programs.

1. IMR programs have the potential to be regressive. If the cost of repairs were equal for all segments of the population, poorer people would have to pay a greater fraction of their income to get their automobile repaired. Actually, if (as it appears to be the case) poorer people own older vehicles, which may require even more repair than the average, the regressiveness is accentuated. This impact on the older vehicle and its owner can be quite severe. If you own an automobile worth $500.00 that you need for transportation to work, and the IMR test indicates that you require a valve job which costs more than your car is worth, what are you going to do? The potential for getting around the system is great in the above-mentioned case, since a fake or illegal sticker for $10 would appear to be a better deal to the person who could not afford a complying, presumably more expensive, vehicle.

2. Since more IMR programs are emissions oriented, the testing required can be complicated and expensive, although work is underway at EPA to develop short, cost-effective tests.

3. As is the case with retrofit programs, an expensive administration, testing, and enforcement organization will be required to insure that the goals of the program are met.

4. The cost of the maintenance and/or repairs can in some cases be high.

We conclude that IMR programs should not be considered as only fuel economy improvement options, but that the improvements in fuel economy attributable to such an emission control program should be considered when analyzing its cost effectiveness.

### *Improvement of New Vehicle Fuel Economy*

There are several methods by which the fuel economy of new vehicles can be improved. The near-term time frame of this paper tends to rule out a switch to new engine types, but there is potential for some new engines, especially the diesel in some vehicles in just a few years, if the work reported by Volkswagen and General Motors is any indication.

The techniques for vehicles equipped with the conventional engine involve both engine/emission control system modifications and vehicle modifications. Engine/emission control system modifications include more efficient aftertreatment devices. These devices, such as more efficient catalysts and/or exhaust port liners and air injection systems, allow engine recalibration to improve fuel economy. Changes of this type (catalysts) have at ready been introduced in model years 1975 and 1976, and have enabled the new car fleet average to improve from 13.9 mpg in 1974 to 17.6 mpg in 1976 (ref. 2), a gain of 27 percent.

In the near future, advances in fuel metering—such as fuel injection or sonic carburetion, electronic control of engine and emission control parameters, and design and development work to make the average vehicle as good as the best currently demonstrated vehicles—are expected to have equally large benefits.

Other vehicle-related improvements involve upgrading transmission efficiency. In the near term, a massive shift to manual transmissions is probably not practical, but improvements to today's automatic transmission via the addition of extra gears and the introduction of torque converter lockup on one or more gears is now being considered for near 1980 introduction. Continuously variable transmissions (CVT's), however, appear to be beyond the near-term time frame of this paper.

The structure of the vehicle can also be changed to provide more passenger room per pound of vehicle. New body designs—such as unibody construction and the substitution of more weight-efficient materials (plastics, aluminum, and high-strength/low-alloy steels)—have potential. Improvements in vehicle aerodynamic drag and tire rolling resistance also appear possible. Additionally, more lightweight automobiles could be produced compared to today's market share of such vehicles.

Performance reductions that allow the engine to operate less throttled more of the time can have fuel economy benefits, although the marketability of such an approach on a large scale must be investigated. All of the above approaches are now being considered for application in the near term. The likely improvement in new car fleet average fuel economy has been estimated by Malliaris (ref. 3). For changes of the kind described above, which could be instituted around 1980, Malliaris estimated a new car fleet average fuel economy of 26.9 mpg. This corresponds to an 88 percent improvement compared with 1974.

Like the other approaches discussed, improvement of new-vehicle fuel economy has advantages and disadvantages. Among the advantages:

1. More sophisticated technical approaches can be used, compared to retrofit devices.

2. The new vehicles will meet the applicable emission standards.

3. The experience and expertise of the automobile companies in the design and development of the vehicles is utilized.

4. Possibly the greatest fuel savings can be realized with this approach.

Among the disadvantages:

1. Only new vehicles are affected. This means that the full benefits of such a program will not be felt until all the older vehicles are replaced.

2. The fuel economy improvements will increase the initial cost of automobiles.

### *Summary*

There are no simple answers for improving automobile fuel economy in the near term. All of the approaches have advantages and disadvantages. One thing that all of the approaches have in common, however, is that they will cost money. Whether or not the extra costs will be justified in fuel economy savings must be investigated thoroughly.

The actual route to be taken to achieve near-term improvements depends on yet-to-be-made policy decisions that are beyond the scope of this paper. Before such decisions are made, however, we feel that detailed, in-depth answers to the following questions must be determined.

1. How much fuel needs to be saved?

2. How quickly do the fuel conservation benefits need to be realized?

3. How much money, manpower, and time should be expended?

4. How will the achievement of environmental goals be affected?

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# THERMODYNAMIC ANALYSIS OF INDUSTRIAL ENERGY CONSERVATION OPPORTUNITIES

Elton H. Hall, Ph.D.[1]

## *Abstract*

*Thermodynamic analyses were conducted of the processes employed in the steel, copper, aluminum, glass, synthetic rubber, selected plastics, and paper industries. Results of the calculations for these seven industries include the minimum theoretical energy, the efficiency of selected unit processes, and the effect of certain process changes on the energy use. A computer model was developed to perform the necessary calculations. The model performs the customary energy balances based on the first law of thermodynamics. More importantly, availability losses are calculated according to the second law of thermodynamics. The model is general and can be applied to an entire industrial process or to any of the unit operations which are employed within the process. The results identify where large energy or availability losses occur. The model is a powerful tool for identifying those operations in which significant fuel savings can be realized through straightforward modifications. On the other hand, the model will also show where the potential for energy conservation is limited by the irreversibilities inherent in the basic processes employed. Such a definition of the nature of the various availability losses is invaluable in directing the attention of process engineers to those operations which offer the greatest potential for overall fuel savings.*

## INTRODUCTION

Thermodynamic analyses of the use of energy in each of seven, energy intensive, basic industries were performed to evaluate the potential fuel savings for various energy conservation options (ref. 1). The industries included were: steel, copper, aluminum, glass, rubber, selected plastics, and paper.

Thermodynamic analyses were conducted to determine the theoretical minimum energy required to carry out the processes associated with each industry. These calculations were performed for each industry as a whole and for each of the major unit operations within each industry. Comparison of the results of these calculations with data on actual energy use serves to identify those unit operations for which large differentials exist between the actual energy use and the theoretical minimum energy requirement.

Conventional thermodynamic analysis of energy use commonly consists of conducting energy (heat and work) balances around the process, an approach based on the first law of thermodynamics. Each industry was analyzed by this method. However, for the purpose of evaluating the potential for reducing the fuel requirements for a given process, it is more instructive to calculate the losses of availability. Availability is a thermodynamic quantity which is equal to the maximum work which can be obtained from a system by bringing it, by reversible processes, to a state of equilibrium with its environment. According to the first law, energy must be conserved, but availability can be destroyed and its destruction is associated with irreversibility. Calculation of availability losses is done by means of analysis based on the second law of thermodynamics and the results of this type of calculation also are presented.

It is important to note that the theoretical minimum energy calculated for a given process is that energy which would be required if each step in the process were conducted reversibly. In addition, the theoretical minimum energy requirement does not include any consideration of the time required for processing. Since all real processes are, in fact, irreversible to a greater or lesser degree, and, since all real processes require a finite time, it follows that the theoretical minimum energy is an unachievable goal. The value of the combined first and second law approach is that those unit operations in which large availability losses occur can be identified, and (by adjustment of parameters) the amount of availability and consequently the amount of fuel which might be saved (through modification of operating conditions and procedures) can be calculated. In addition, the analysis also shows where the potential for fuel conservation is limited by the irreversibilities inherent in the basic processes employed. In such cases different and more reversible processes would have to be employed in order to further reduce the fuel consumption. If no viable alternative to the basic process is available, then the minimum energy consumption achievable in that industry may be significantly greater than the theoretical minimum based on a hypothetical, completely reversible, instantaneous process. Such a definition of the nature of the various availability losses will be useful in directing the attention of process design engineers to those operations which offer the greatest potential for overall fuel savings. Furthermore, the ability to predict the potential fuel savings of various design modifications by means of a combined first and second law approach will enable the design engineer to choose, within the constraints of the costs of the proposed modifications, the design which requires the least fuel.

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A computer model was developed during this study to facilitate the required computations. The code can be operated in a batch/interactive mode, allowing answers to be displayed in real time to questions such as, "what is the potential fuel saving if a certain heat exchanger is operated at a higher temperature?"

In this paper a brief summary of the thermodynamic approach is given, and some selected examples of analyses of the potential fuel savings of proposed process changes are presented.

## PROCESS UNIT ANALYSES

### *Energy and Efficiency*

The energy of a flow stream is determined by the stream composition and mass flow and by the energy of the components in the stream. Thus, the energy, $E_i$, of stream i is given by the mass flow rate, $M_i$, times the sum of the mole fraction, $x_{ij}$, of component j in stream i, times the enthalpy, $h_j$, of component j:

$$E_i = M_i \Sigma x_{ij} h_j \tag{1}$$

The efficiency of a process unit was defined as:

$$\text{Efficiency} = E_{use}/E_{in} \tag{2}$$

where

$E_{use}$ = total useful energy output,

$E_{in}$ = total energy input including heat and work inputs.

### *Availability and Effectiveness*

The availability of a stream is the maximum work which can be obtained by bringing the stream to complete equilibrium with the reference atmosphere. This means that the stream is brought to the temperature of the reference atmosphere ($T_0$), and to the total pressure of the reference atmosphere ($P_0$), and the partial pressure of each component of the stream is brought to its value in the reference atmosphere.

Availability per unit mass, a, is defined by the relationship:

$$a = h - T_0 s,$$

where h is the enthalpy, s is the entropy, and $T_0$ is the temperature of the reference atmosphere. The availability, $A_i$, of stream i is related to the component availabilities by:

$$A_i = M_i \Sigma x_{ij} (h_j - T_0 s_{ij}). \tag{3}$$

The summation is done over all components in each stream. The enthalpy, $h_j$, depends only on the component and stream temperature; however, the entropy, $s_{ij}$, generally depends upon the concentration of each component in the stream as well as the temperature.

Effectiveness is the term used to measure the performance of a process in terms of availability. Three definitions of effectiveness have come into use and all three have been calculated by the thermodynamic model. However, for the purposes of this summary, only one definition will be considered:

$$\text{Effectiveness} = A_{out}/A_{in} \tag{4}$$

This effectiveness definition is analogous to the definition of efficiency and in many cases its value is close to the value of the process efficiency.

In this definition the numerator is the total availability output, $A_{out}$, and not just the availability of the product stream or the product stream and the streams where waste energy is recovered. This approach is somewhat different than that taken in defining efficiency where the numerator is the energy of the useful output streams. The efficiency is a measure of how well some specific product (the useful output) utilized the total input energy. Effectiveness, on the other hand, considers the maximum work (useful output) of all the flow streams leaving the process, whether or not the availability of those streams is, in fact, used. A process is charged only with the destruction of availability in the process, but is not charged with the destruction (by waste) of the availability in process output streams. This represents a fundamental difference between the calculation of efficiency and effectiveness.

## ANALYTICAL APPROACH

The analytical model for thermodynamic analysis was set up to analyze the energy and availability fluxes through any specified process unit. A process unit can be any process, subprocess, or combination of processes up to an entire plant or industry. The same analytical model was used for studying processes in all seven industries; there is no need to specifically tailor the method of analysis to a specific process.

The system to be analyzed is defined in terms of the input and output streams as shown schematically in figure 1. The mass flows entering and leaving, the heat inputs and losses, and the work inputs and outputs are included. The specification of heat inputs and losses is fairly straightforward. The work input and output category includes electrical and mechanical work done on (input) or done by (output) the process unit. The electrical work inputs can be given in terms of direct input or fuel equivalent; in the latter case a heat loss should be specified to account for generation and transmission losses. In the analysis performed in this study, each process unit was first evaluated using the direct

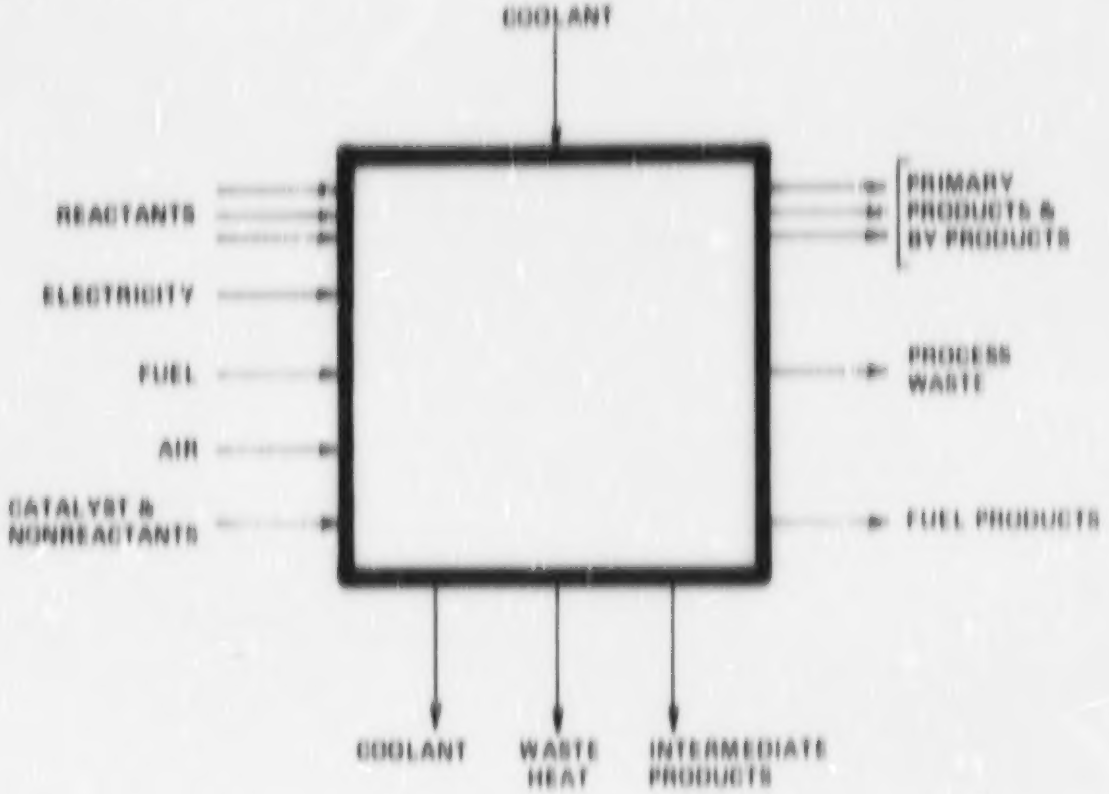

Figure 1. Process definition for thermodynamic analysis.

input energy and availability values for utilities, steam, and electricity. This procedure was used so that the direct process losses could be quantified. Once this step was completed, the process was reexamined, and the fuel equivalents of the steam and electrical power used were considered. The total fuel and fuel equivalent required for a process or industry is the important quantity in the larger view of national fuel use. The direct energy consumption for a process, however, provides the basis for studying that process and improvements in it.

The energy and availability of flow streams entering and leaving a process unit provide a unique way of defining the process unit from a thermodynamic viewpoint. The flow streams are specified by their composition, pressure, temperature, and mass flow rate. The composition specification includes identification of the chemical species, mole fraction or number of moles, molecular mass, and partial pressure in the environment. The enthalpy and entropy of the species may be input directly, but usually are calculated by property subroutines. The flow streams are designated as inflow or outflow by positive or negative values, respectively, for the mass flow rate. Each outflow stream, and each outflow of heat may be designated as a useful output, and thus be used in the calculation of efficiency. All work outputs are considered useful.

The thermodynamic model performs a first law (heat balance) analysis and a second law analysis on process unit. The model does not check the mass balance for the process; it is assumed that the investigator has accounted for all the important flow streams and has an adequate mass balance for the process unit. The model first performs the first law analysis or heat balance. The investigator may optionally specify one flow stream to have a variable temperature or mass flow rate. If this option is used, the temperature or mass flow (whichever is designated) is adjusted so that the first law is more closely satisfied. An iterative procedure is used to successively calculate better solutions to the analysis. The iterative process is ended when a maximum number of iterations is reached (usually 8) or when the first law is satisfied to within 0.5 percent of the total input energy.

When the first law analysis has been satisfactorily completed the model goes on to perform the second law analysis. The availability of each flow stream is calculated from the enthalpy, entropy, and pressure of the stream. Heat losses are assumed to be availability destructions and hence do not show up in the availability summary. Work inputs and outputs are considered to be fully equivalent to availability inputs and outputs. Since the second law of thermodynamics is an inequality, there is no way to balance the availability flows for a process the way energy flows must balance to satisfy the first law. Thus, the mass flow rates and temperatures which satisfied the first law are used in the model for the second law analysis without change. Since the evaluation of the thermodynamic properties is basic to the calculation of energy, availability, efficiency and effectiveness, the property calculations are discussed in the following section.

### *Evaluation of Thermodynamic Properties*

The calculation of the energy and availability of a flow stream requires the evaluation of the enthalpy and entropy of the components of the flow stream. The thermodynamic model was set up so that the enthalpy and entropy of a stream component could be directly put into the model along with the mole fraction and molecular mass of that component, or the values were calculated by the appropriate property subroutine for the component. The enthalpy was calculated at stream temperature, and the entropy was calculated at the stream temperature and the partial pressure of the component in the stream. The temperature dependence of these properties was obtained by integrating the specific heat of the component from the reference temperature (80° F) to the stream temperature, and adding in all the enthalpy and entropy changes at transformations and phase changes. The enthalpy and entropy of formation also were added to the corresponding values as calculated above.

## SUMMARY OF RESULTS

### *General*

An attempt was made in each of the industries to calculate the minimum amount of energy and availability required to convert the raw materials of the industry into the products of that industry. In the steel, container glass, and aluminum industries, minimum energy and availability requirements could be, and were calculated. The minimum energy and availability so calculated do not depend upon any process or process details. In the other four industries, such minimum values were not calculated because the energy and availability of the raw materials are greater than they are for the products. Theoretically these four industries, copper, rubber, plastics, and paper do not require energy to convert their raw materials into their products. In fact, however, the processes currently in use for converting the raw materials into products do require significant amounts of purchased energy. In some of these industries, particularly rubber and some plastics, the heat of polymerization (which is liberated during the making of the rubber or plastic) is available only at temperatures close to ambient temperature. Thus, it is only with great difficulty and expense that the heat of polymerization could be used.

In addition to determining the theoretical minimum energy and availability required for each industry, the inefficiencies of each industry and many of the industrial processes were examined in detail to identify areas for process improvement. Improvements are possible in all industries, and all the processes studied have room for some improvement. The efficiency and effectiveness of energy use in industrial processes varies widely, some processes waste relatively little of their input energy while other processes waste nearly all their input energy.

A brief summary of the numerical results of the analyses of seven major fuel-using industries is given in table 1. The seven industries, or major product segments in the cases of rubber and plastics, were analyzed on the basis of both the first and second laws of thermodynamics.

The data presented in table 1 are the overall values of efficiency and effectiveness for the processes analyzed in each industry. The rubber and plastics industries are broken down in terms of the major products since these products and their manufacturing processes are quite different. The data are also presented in terms of direct equivalent and fuel equivalent input. The direct equivalent is based on direct conversion of electrical input to Btu's for each process, i.e., the electrical generation and transmission losses are not included. The fuel equivalent input is based upon the fuel required to generate all electricity consumed (at 33 percent generation and transmission efficiency). The direct input is representative of existing industry conditions since few industries generate significant quantities of their own electricity. The direct input does not, however, reflect the true demand on resources which the fuel equivalent does. Thus, under a total energy concept, i.e., each plant generating its own power and recovering its own waste heat, the fuel equivalent would be the only true basis for energy and availability calculations. As shown in table 1, th

Table 1. Efficiency and effectiveness summary for seven industries

| Industry | Percent | | | |
|---|---|---|---|---|
| | Direct equivalent | | Fuel equivalent | |
| | Efficiency | Effectiveness | Efficiency | Effectiveness |
| Steel | 42.0 | 40.1 | 41.0 | 39.0 |
| Copper | 3.5 | 9.2 | 2.7 | 7.10 |
| Aluminum | 29.6 | 32.6 | 14.2 | 15.1 |
| Container glass | 23.9 | 22.1 | 21.3 | 19.5 |
| Rubber | | | | |
| High-temperature | 92.4 | 96.2 | 92.4 | 96.2 |
| Selected plastics | | | | |
| Polyethylene | | | | |
| Low-density | 83.5 | 93.1 | 79.0 | 88.0 |
| High-density | 75.1 | 87.9 | 73.4 | 85.5 |
| Polystyrene | 82.7 | 97.9 | 82.2 | 97.2 |
| Polyvinyl chloride | 65.5 | 90.3 | 65.0 | 89.5 |
| Paper | 44.3 | 44.5 | 44.3 | 44.5 |

industries have efficiencies and effectivenesses which vary greatly. The high efficiencies of rubber, plastics and, to an extent, paper, reflect the fact that these industries are essentially processing fuels. The energy value of the feed-stock and product in these processes leads to a falsely high value of efficiency.

Another measure of process performance is given by the availability destruction for the process and/or the ratio of availability destruction to the availability of purchased fuels and electricity. These two quantities are listed for each industry in table 2. The fact that the availability destruction is greater than the total purchased availability for some industries indicates that some of the feedstock availability is being destroyed. Despite the high efficiency of several of the rubber, paper, and plastics manufacturing processes, these processes have large availability destructions relative to their purchased availability. These cases illustrate that a high first law efficiency does not always indicate good process performance or even low availability destruction.

A further comment must be made on the analyses conducted. The input data used for each process were based on industry average values wherever possible. These analyses do not necessarily represent the true conditions in any specific plant, process, or industry. In any industry some plants will have better performance than that shown. These plants will not be as easy to improve as other less efficient plants. Specific conclusions for any plant must be based on analysis of that plant in detail.

## SOME SPECIFIC INDUSTRY RESULTS

### *The Steel Industry*

The theoretical minimum energy required for steel production is $7.52 \times 10^6$ Btu/ton. The steel industry uses approximately $26 \times 10^6$ Btu/ton of steel produced. Although the theoretical minimum energy requirement cannot be achieved in any real process, there appears to be an opportunity for significant increases in efficiency of fuel utilization.

An important aspect of this study was the determination of the potential effect of certain process modifications on fuel requirements. A rather simple example, the blast stove, will serve to illustrate the approach.

Table 3. Availability destruction, purchased availability, and their ratio

| Industry | Availability destruction[a] | Purchased availability[b] | A.D./P.A. |
|---|---|---|---|
| | ($\times 10^6$ Btu/ton of product) | | (percent) |
| Steel | 12.0 | 17.8 | 67 |
| Copper | 62.2 | 36.6 | 170 |
| Aluminum | 61.8 | 89.6 | 69 |
| Glass containers | 8.9 | 10.7 | 83 |
| High-temp. rubber | 2.1 | 1.5 | 140 |
| Low-density polyethelyene | 3.3 | 1.9 | 174 |
| High-density polyethelyene | 6.3 | 2.8 | 225 |
| Polyvinyl chloride | 2.7 | 1.6 | 169 |
| Polystyrene | 1.9 | 1.8 | 106 |
| Paper | 25.8 | 1.6 | 1,616 |

[a] Based on direct equivalence of electrical input.

[b] Includes direct equivalent of electrical input; does not include feedstock availability.

The blast stoves are fuel-fired air preheaters for the blast furnace, providing air at 1600 to 2000 F. The stoves are usually fired with blast furnace gas. A summary of energy and availability for a blast stove is given in table 3, in units of $10^6$ Btu/ton of steel. The availability destruction in blast stoves, 0.66 x $10^6$ Btu/ton, is approximately 54 percent of the input availability of the fuel. Combustion irreversibilities account for about 40 percent of this total availability destruction, and about 20 percent is due to heat losses to the atmosphere. The remaining 40 percent of the total availability destruction is due to transferring heat across the temperature difference between the combustion products and the air. This availability destruction would be reduced at higher operating temperature with improved insulation to hold down heat losses.

The effect of producing higher temperature blast air was analyzed together with other blast furnace modifications, including the charging of hot or preheated raw materials to the blast furnace. These process modifications do not change the total input energy to the blast furnace, but rather shift a portion of the energy requirement from the primary fuel to the raw material inputs. The primary fuel rate can be reduced by the energy required to heat the raw materials from ambient temperature (current charging temperature) in the modified process. The results of an analysis of higher charging temperatures are summarized in table 4. In the eight cases presented, only the material charging temperatures and the coke rate were varied, hence, the total energy input to the blast furnace is the same for all eight cases.

The rationale behind the particular temperatures chosen for the analysis is: (1) not to quench hot materials before charging (coke and sinter); (2) to preheat large size solid material (pellets); (3) to increase blast temperature; and (4) to preheat ore.

Increased coke temperatures are attractive because coke is produced at temperatures up to 2,000° F and is presently quenched to ambient temperature. The sensible heat of the coke is not utilized at all in present practice. The reason for quenching is to prevent combustion of the coke since its ignition temperature is near 1,000° F in air. The 1,000° F coke temperature is an

Table 3. Energy and availability summary for a blast stove

|  | Energy | Availability |
|---|---|---|
|  | ($10^6$ Btu/ton of steel) |  |
| **Input** |  |  |
| Blast furnace gas | 1.19 | 1.22 |
| **Output** |  |  |
| Air blast | 0.91[a] | 0.47 |
| Combustion products | .18 | 0.09 |
| Heat loss | .10 | -- |
|  | 1.19 | 0.56 |
| Efficiency | 76 percent |  |

[a] Considered useful output for efficiency calculation.

upper limit on coke temperature without inert gas cover, and 1,200° F might be possible with inert gas cover.

Increased sinter charging temperature is reasonable since, like coke, sinter is usually produced onsite at high temperatures and is currently quenched. No combustion problems are likely as with coke, although some oxidation could take place at high temperatures (1,000° F) in open air. Pellets are produced hot, but offsite, and would have to be preheated onsite as would iron ore. Both could be preheated with inert gas from quenching of coke, slag, iron, or steel. Preheating of pellets would present fewer air pollution control problems than preheating iron ore with a gas stream.

Higher blast air temperatures not only allow reducing the coke rate at the blast furnace but increase the effectiveness of fuel utilization at the blast stove. Increasing the blast air temperature from 1,800° to 2,100° F in the blast stove analyzed previously, results in a 15 percent increase in fuel consumption, a 2 percent increase in efficiency, and 14 percent increase in effectiveness for the blast stove without benefit of improved insulation. Raising the blast temperature from 1,800° to 2,100° F, as in conditions 6 and 8 in table 4, results in a savings of 0.4 × $10^6$ Btu (per ton of steel) of coke with an increase of 0.18 × $10^6$ Btu (per ton of steel) of blast furnace gas. Since byproduct fuel gases are not fully used in many steel plants, increased blast temperatures offer a potential savings of 0.55 × $10^6$ Btu (per ton of steel) in coal requirements or a 2 percent overall fuel saving.

*The Aluminum Industry*

The theoretical minimum energy required to refine bauxite and reduce the refined alumina to aluminum is 28.3 × $10^6$ Btu/ton of aluminum. The average estimated energy consumption in the aluminum industry is 98 × $10^6$ Btu/ton, if the electrical input is expressed in direct equivalent.

An example of possible process modifications analyzed in the aluminum industry involved alumina calcining.

The calcining process removes water of hydration from the alumina trihydrate produced by the Bayer process and thus provides alumina for electrolytic reduction. The energy and availability summary for a representative calcining process is given in table 5. The useful output is the dry alumina, at 80 F, ready for transportation to the reduction cell. The off gases have been used for preheating the incoming alumina hydrate and some energy from the output alumina is credited to air preheating in this analysis. However, the calcining step is not particularly effective in its present state, and a fluidized-bed calciner has been suggested as an improvement.

Table 4. Fuel reduction allowed by increased raw materials charging temperatures in a blast furnace

| | Charging temperatures (°F) | | | | Coke rate |
|---|---|---|---|---|---|
| | Coke | Ore | Sinter & pellets | Blast | (relative to baseline) |
| 1. Baseline | 80 | 80 | 80 | 1,500 | 1.00 |
| 2. Coke, burden | 1,000 | 80 | 500 | 1,500 | 0.97 |
| 3. 2 + blast | 1,000 | 80 | 500 | 1,900 | 0.94 |
| 4. 2 + ore | 1,000 | 500 | 1,000 | 1,500 | 0.94 |
| 5. 2 + ore and blast | 1,000 | 500 | 1,000 | 1,900 | 0.91 |
| 6. Maximum burden | 1,250 | 1,000 | 1,000 | 1,500 | 0.93 |
| 7. 6 + blast | 1,250 | 1,000 | 1,000 | 1,900 | 0.90 |
| 8. 7 + blast | 1,250 | 1,000 | 1,000 | 2,700 | 0.89 |

Table 5. Energy and availability summary for an alumina calciner

| | Energy | Availability |
|---|---|---|
| | ($10^6$ Btu/ton of aluminum) | |
| **Input** | | |
| Alumina (80° F) | 0.00 | 0.00 |
| Fuel | 9.98 | 9.07 |
| Total | 9.98 | 9.07 |
| **Output** | | |
| Alumina (1,500° F) | 2.07[a] | 2.10 |
| Off gas | 5.58 | 2.14 |
| Heat loss | 2.34 | -- |
| Total | 9.98 | 4.24 |
| Efficiency | 21 percent | |

[a] Considered useful output for the efficiency calculation.

The energy and availability summary for a fluidized-bed calciner is given in table 6. The primary operational improvements over conventional rotary kiln calciners is the improved effectiveness of preheating input materials and the resultant decrease in exit temperature of alumina and off-gases. The fuel rate requirement of the fluid-bed calciner is lower than that of the kiln because of the improved preheating of the alumina and combustion air, and thus the fluidized-bed calciner can achieve a 30 percent reduction in fuel requirements. The off-gases from this process could still provide some of the heat required for the steam generation for the Bayer process. The energy and availability flows for these two calcining methods are shown in figure 7. The energy and availability of both the alumina and the combustion products are lower for the fluidized-bed calciner, thus allowing reduced fuel input.

*The Glass Container Industry*

The theoretical minimum energy required to produce glass for containers is 2.16 x $10^6$ Btu/ton of glass melted. The glass container industry currently uses 11.0 x $10^6$ Btu of *purchased* fuel and electricity (direct equivalent).

An important process improvement currently being studied by the glass industry for future application is the preheating of the batch with exhaust gases from the furnaces. The upper temperature limit for preheating the batch presently appears to be about 700° C. The thermodynamic analysis of the melt furnace and its regenerator indicates that with no heat losses from the regenerator there is enough energy and availability in the furnace exhaust gases to preheat the incoming combustion air to present levels and to preheat the batch to 700° C. Although heat losses cannot be completely eliminated, improved insulation, within materials and process constraints, and the use of reheat and conditioning furnace exhaust gases for initial preheating could be expected to provide sufficient batch preheating. An energy and availability summary for a combined melting furnace and regenerator is given in table 7, and that for such a combined melting furnace with air and batch preheaters

Table 6. Energy and availability summary for an alumina calciner (fluidized bed)

| | Energy | Availability |
|---|---|---|
| | ($10^6$ Btu/ton of aluminum) | |
| **Input** | | |
| Alumina | 0.00 | 0.00 |
| Fuel | 7.03 | 6.39 |
| Total | 7.03 | 6.39 |
| **Output** | | |
| Alumina (600° F) | 1.10[a] | 1.49 |
| Off gas (80° F) | 4.25 | 1.54 |
| Heat loss | 1.68 | -- |
| Total | 7.03 | 3.03 |
| Efficiency | 16 percent | |
| Effectiveness | 47.4 percent | |

[a] Considered useful output for the efficiency calculation.

is given in table 8. The reduction in fuel consumption for such an arrangement amounts to 14.8 percent (fuel input of 6.300 x $10^9$ Btu in table 8 versus 7.406 x $10^9$ Btu in table 7). The effect of batch preheating on energy requirements is shown graphically in figure 3. In this case, the energy and availability of the product glass are unchanged, but these values for the combustion products are lower with batch preheating.

The overall efficiency predicted with batch preheating, 38.6 percent based on the direct equivalent of electrical inputs, approaches the maximum achievable by melting furnaces of conventional design. The remaining availability destructions result largely from combustion irreversibilities and from heat transfer across a finite temperature difference.

## CONCLUSIONS

The results of the study show the value of the combined first and second law approach in identifying those operations in a process where significant fuel savings might be achieved and in estimating the amount of fuel which might be saved through specific process modifications. Some examples have shown potential fuel savings of 30 percent. Suggested process changes have been analyzed from the energy and availability viewpoint only. Final decisions regarding the desirability of implementation of any process modification must be based upon analysis of all of the costs required to achieve the anticipated energy savings.

## ACKNOWLEDGMENTS

This paper is based upon the results of a study conducted at Battelle's Columbus Laboratories for the Federal Energy Administration entitled, "Evaluation of the Theoretical Potential for Energy Conservation in Seven Basic Industries" (Contract No. 14-01-0001-1666). The author wishes to acknowledge the assistance of the FEA Technical Project Monitors, W.

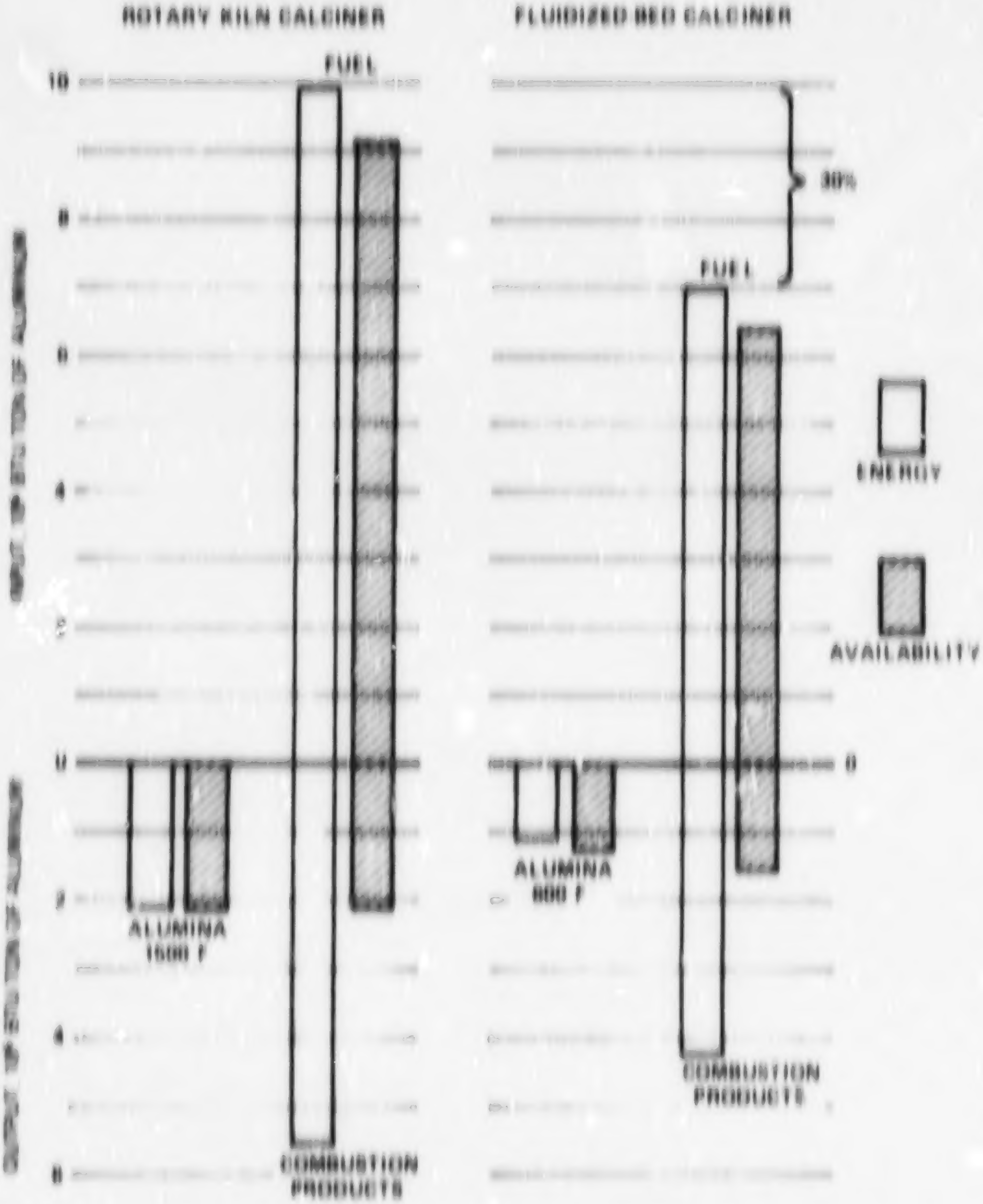

Figure 2. Comparison of rotary kiln and fluidized bed calciner.

Table 7. Energy and availability summary for a combined melting furnace and regenerator

|  | Energy | Availability |
|---|---|---|
|  | ($10^6$ Btu/ton of glass) |  |
| **Input** |  |  |
| Batch | 0.637 | 0.571 |
| Fuel | 7.465 | 6.786 |
| Electricity (direct equivalent) | 0.220[a] | 0.220 |
| Total | 8.322 | 7.567 |
| **Output** |  |  |
| Glass | 2.787[b] | 1.327 |
| Combustion products | 1.464 | 0.621 |
| Losses | 4.071 | --- |
| Total | 8.322 | 1.948 |
| Efficiency | 33.5 percent |  |
| Effectiveness | 25.7 percent |  |

[a] Electricity expressed as fuel equivalent = 0.677. If this value is used as the electrical input, the efficiency and effectiveness rates would be: Efficiency = 31.7 percent; Effectiveness = 24.2 percent.

[b] Considered useful output for efficiency calculations.

Table 8. Energy and availability summary for a melting furnace combined with batch and air preheaters

|  | Energy | Availability |
|---|---|---|
|  | ($10^6$ Btu/ton of glass) |  |
| Input |  |  |
| Batch | 0.637 | 0.571 |
| Fuel | 6.360 | 5.786 |
| Electricity (direct equivalent) | 0.22[a] | 0.22 |
| Total | 7.217 | 6.577 |
| Output |  |  |
| Glass | 2.787[b] | 1.327 |
| Combustion products | 0.670 | 0.2<br>(estimated) |
| Losses | 3.76 | ... |
| Total | 7.217 | 1.527 |

Efficiency 38.6 percent
Effectiveness 23.2 percent

[a] Electricity expressed as fuel equivalent = 0.677. If this value is used as the electrical input, the efficiency and effectiveness rates would be: Efficiency = 36.3 percent; Effectiveness = 21.7 percent.

[b] Considered useful output for the efficiency calculations.

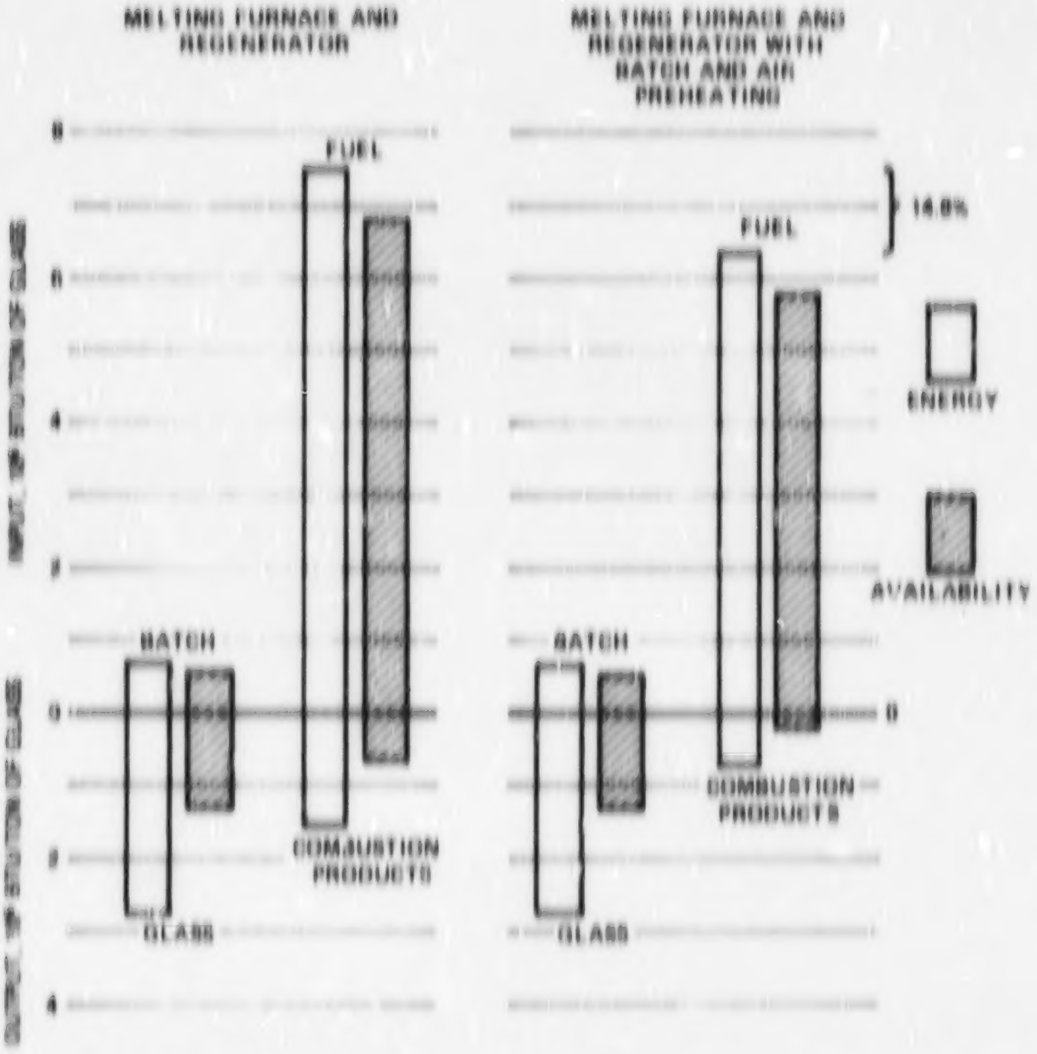

Figure 5. Effect of batch preheating on energy requirements.

Mutryn and T. Gross, and the efforts of other Battelle-Columbus staff who participated in that project: W. T. Harris, L. D. Reed, J. Varga, Jr., D. N. Williams, K. E. Wilkes, R. E. Johnson, W. J. Mueller, E. J. Bradbury, and W. J. Frederick. Battelle's Columbus Laboratories is grateful to the Federal Energy Administration for the financial support of the study and for permission to summarize the results in this symposium.

## REFERENCE

1. Elton H. Hall, et al. "Evaluation of the Theoretical Potential for Energy Conservation in Seven Basic Industries," final report by Battelle's Columbus Laboratories to the Federal Energy Administration, Contract No. 14-01-0001-1666, July 1975. Available through NTIS as PB 244 772/AS.

4 November 1975

## LUNCHEON ADDRESS

## ENERGY AND ENVIRONMENTAL RESOURCES

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# ENERGY AND ENVIRONMENTAL RESOURCES

John A. Green*

## Abstract

*Over 50 percent of the Nation's coal resources, almost 50 percent of the reserves, and more than 80 percent of the strippable reserves are located in the States of Colorado, Utah, Wyoming, Montana, South Dakota, and North Dakota. This area supplied about 7 percent of the Nation's 1973 coal production. Shale oil located in the region's Green River formation represents all of the Nation's reserves of this energy resource. Oil and gas reserves, uranium ore reserves and output, and nuclear energy in the area will supply an increasing proportion of national requirements. The economic and social impacts of environmental programs in this six-State region are discussed below, and, after an outlining of various technologies of energy resource development, the environmental impacts to the land and people involved are listed.*

I am indeed pleased to address this joint EPA/ERDA conference on the environment and energy conservation. Hopefully, sessions like these will allow members of industry, government, and the public to exchange ideas and help minimize the adverse impacts while supplying energy demanded by the Nation as a whole as well as State and local entities.

Our two agencies, the States, local government, and other appropriate Federal agencies must work closely together because of the obvious interrelationships of the environmental impacts from extraction and conversion of energy resources.

True, there will have to be some tradeoffs between energy resource production and protecting the environment. Developing our natural resources will be accompanied with some environmental degradation. That degradation must be minimized.

As I see it, we have two priorities. First, we must make sure that the Nation's energy needs are satisfied. Second, we must consider local priorities. In both of these categories, however, we must be sensitive to the economic and social impacts of environmental programs. The environment must not be sacrificed, nor be the scapegoat for the production or the delay of energy resource development initiatives.

We are all aware of the problems and challenges ahead. We as a Nation must become more energy independent. To reach that goal the Administration has supported and initiated energy research, demonstration, and commercialization programs. We are here to help balance seemingly conflicting goals through cooperation, technology development, and cooperation with the States.

In this region, we are farming and ranching and living on top of a vast coal field. We realize that some of this coal must be burned to supplement Appalachian coal and finite supplies of natural gas while other alternatives for energy resource development are being researched. However, before we can burn any coal we must, of course, mine it, and there is a whole host of environmental, social, and cultural problems associated with the mining of coal.

You here today know about the blighted lives, lungs, landscapes, human harm, and environmental havoc that accompanies the mining of coal—not only in this country but everywhere in the world. We can no longer accept these kinds of impacts as the inevitable, if unfortunate, price of getting coal out of the ground and into our power plants. The mining of both eastern and western coal must be done according to careful and comprehensive advance planning and accompanied every step of the way by effective efforts to keep adverse impacts to the lowest levels possible.

For its part, EPA will continue to do whatever it can—consistent with its responsibilities under the law—to assist and encourage the greater use of coal for electric power. Under the clean fuels policy we identified 13 major coal burning States whose emission limits were stricter than required to meet national primary ambient air standards. We estimated that, by the second half of this year, these standards would have prevented the burning of roughly 110 million tons of current coal production, thus leaving some areas no choice but to turn to oil in order to meet clean air standards. Thus far, seven of these States have revised their implementation plans. We have thus freed approximately half of the 110 million tons of coal for burning, and expect to free the other half by the end of the year. We have also advised the remaining States and territories of any regulations in their plans that are more stringent than necessary to meet air quality standards to protect public health. We hope that, wherever possible, these regulations will be revised to permit even greater use of available domestic coal.

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*Region VIII Administrator, Environmental Protection Agency, Denver, Colorado.

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In addition, EPA is currently cooperating with the Federal Energy Administration (FEA) to identify power development facilities that could convert to the burning of coal, but we are insisting on consistent health standards at the same time.

In the western States much of the so-called overburden that stands between the "stripper" and the coal is prime grazing land. The mine-mouth conversion plans that many companies hope to construct here would consume vast amounts of already scarce western water that is required for both crops and cattle. Shouldn't we consider a possible food shortage as well as the shortage of energy resources?

A 70-year-old western rancher whose home and range rest upon a vein of coal ripe for stripping remarked, "We know coal is going to be mined and I think we can face the fact that the development, the population, is going to come into this country more. But we don't want to be deluged with it all at once. If it can just come here more naturally, and have it on a sensible, rational basis instead of suddenly being inundated. That's what we dread the most."

That rancher has a lot of company out here in the West.

Let's look at some energy development technologies and their environmental consequences.

Coal conversion into electricity, gasification, and liquefaction are processes that utilize coal. Coal gasification has been successfully demonstrated since the 1930's in a few foreign countries, but in these countries environmental considerations were not then considered important. Several gasification plants are currently planned in this country and it has been estimated, based upon $11/bbl crude oil, that by 1985, coal gasification can produce 300 billion cubic feet per year synthetic gas at a normal program rate, and 1,300 billion cubic feet of gas per year at an accelerated program rate.

Coal liquefaction is a developing technology and lacks a history of demonstration. Currently there are no plans for construction of commercial plants in the United States, but it is estimated that 500,000 bbl/day of synthetic oil could be produced on an accelerated program rate.

Now for the environmental impacts of these technologies. Sulfur dioxide emissions and solids disposal are potentially significant problems associated with low-Btu gasification. Air emissions of particulates, hydrocarbons, and carbon monoxides vary according to the process used. Water effluents could be a problem depending upon the method of disposal. Air emissions of particulates, nitrogen and sulfur oxides, hydrocarbons and carbon monoxide, solids disposal, land use, water consumption, and water effluents are all environmental concerns of high Btu gasification. Environmental impacts associated with coal liquefaction are anticipated to be from air emissions of particulates, nitrogen and sulfur oxides, water effluents containing total dissolved and suspended solids, and organics, solids disposal, and land requirements.

Oil shale, known to the Indians and early settlers as the "rock that burns," has long been known as a potential energy resource and today economically recoverable reserves of shale oil are estimated to be 600 billion barrels. By 1985 it is estimated that shale oil production can reach 250,000 bbl/day at a business-as-usual supply rate, and up to 1,000,000 bbl/day at an accelerated supply rate.

In addition to the impacts directly associated with the mining of the oil shale, there are environmental concerns related to anticipated high water consumption—reclamation, revegetation, large land requirements for spent shale and other solid waste disposal, air emissions of particulates, nitrogen and sulfur oxides, hydrocarbons, carbon monoxides and aldehydes, and water effluents containing total dissolved and suspended solids, organics, BOD and COD.

Geothermal energy may make a substantial contribution to United States energy needs by the year 2000. This technology is of particular interest to EPA in this region because most geothermal activity is located in the western third of the Nation and geothermal power is most effective when transformed into electricity at the wellhead.

The major environmental problems associated with geothermal energy production are: hydrogen sulfide emissions, saline water disposal, land subsidence, and land use guidelines. Of the three types of geothermal power plants either now in existence or under development, the closed system hot water type, in which isobutane is vaporized by contact with the hot water through a heat exchanger, may be least detrimental to the environment.

EPA has given increased attention and funding to the development of technologies for the conversion of solid wastes to fuel. A number of technologies for this recycling are now in the pilot stage or early commercial operation stages. Resource recovery of both organics and inorganics is of prime importance. Although the potentially available energy is small, perhaps 1 percent, utilization of these wastes will decrease problems associated with landfills and result in a low sulfur fuel.

Nuclear energy, the unconventional and controversial energy source, bears close study. Radiation release into the environment cannot be tolerated. As of last year, 9.1 percent of the Nation's electrical generating capacity was by conventional fission reactors, and fully 18 percent will be produced by 1980.

The solar energy resource system is a final alternate technology. Such a system includes direct solar radiation, wind power, organic farming, and ocean thermal gradient energy. Land area requirements in this case are considerable.

Our six-State region—including Colorado, Montana, North Dakota, South Dakota, Utah, and Wyoming, is being cast as the supplier of vast supplies of energy for the Nation's needs. Over 60 percent of the Nation's coal resources, almost 50 percent of the reserves, and more than 80 percent of the strippable reserves are located in these States. We supplied about 7 percent of the Nation's 1977 coal production.

Essentially all of the Nation's shale oil reserves are located in the region's Green River formation. ERDA's synthetic fuels program proposes two oil shale plants in this area, each producing 50,000 barrels of crude oil per day. Resource State governors have requested a final veto power to opt out of this resource development program.

Production of oil and gas in this region is expected to increase slightly. We are sitting on top of 6 percent of the Nation's oil reserves and 4 percent of the gas reserves. Tight gas resources in our Region VIII States are about 2½ times the known conventional gas reserves.

This region contains over 40 percent of uranium ore reserves and produced almost 50 percent of the national 1973 uranium ore output. ERDA has predicted that the nuclear industry will satisfy 25 percent of U.S. electricity demands by the year 2000. If that prediction materializes, this region will be called upon to supply a major portion of the requirements.

Our limited water resources are necessary for hydroelectric power. Our States rank second only to the west coast in geothermal development. High rates of solar insolation make this region an attractive solar energy resource. Wind energy, which is in the research and development stage, will benefit from above average wind speeds in the Great Plains region.

People who live here are conservation-minded. Conservation is extremely important to us because it means using less gasoline, which will help us solve air pollution problems we have in Denver, Salt Lake City, and other western cities. Conservation means more effective development of energy resources, which means less environmental degradation. Conservation means less disturbance of the land, less water consumption, and less impact on air quality.

We westerners are also concerned about the socioeconomic impacts of energy development. We have seen how boom growth affects drinking water supplies and also wastewater treatment facilities. We see the need for more schools, roads, and housing for miners, engineers, construction people, and their families. Over 100 small communities in Region VIII may be impacted with growth rates up to 400-500 percent.

Some time ago, EPA recognized the need for a coordinated effort to assess and minimize the environmental impacts of a potential energy resource development program in the western States. A coordinated Federal/State program to evaluate potential environmental impacts from development of coal in the northern Great Plains was set into motion in 1972. This program came into being as a result of my letter to Administrator Ruckelshaus and his subsequent contact and recommendations to secretaries Morton and Butz. EPA Region VIII instituted a total energy resource study effort a little more than a year ago when I established the Office of Energy Activities in order to carry out the coordinated investigatory and planning functions which we felt necessary. This office is in constant communication with State and local agencies and the public regarding energy issues, and coordinates the baseline air and water monitoring activities, technical investigations, and integrated planning and management functions required to determine and predict the before and after effects of energy resource development in Region VIII.

EPA Region VIII's efforts to assess and minimize the environmental impacts from energy development fall into six major categories:

1. 208 water planning activities,
2. air quality maintenance area (AQMA) planning,
3. community assistance programs,
4. 201 facilities design and construction,
5. State program assistance, and
6. Technical investigations.

Section 208 of the Federal Water Pollution Control Act Amendments of 1972 provided funding to allow States to develop the technical framework for meeting the 1983 water quality goal of "providing a water quality which provides for the protection and propagation of fish, shellfish, and wildlife and provides for the recreation in and on the water . . . ."

Areawide waste treatment management planning is to be conducted by local planning agencies in coordination with the State environmental and planning agencies in areas designated by the governor of a State. Section 208 provides 100 percent funding for a 2-year program and will provide local government with resources in order to plan and assess the environmental impacts from energy development. Twenty-year projections of population and industrial growth and the attendant water quality impacts are to be analyzed. Local councils of government are providing this planning function throughout Region VIII. Over $12 million has been obligated to these planning agencies for the formulation and implementation of their 208 plans by 1977.

The attainment and maintenance of the National Ambient Air Quality Standards must be insured by the State air pollution control agencies. In an effort to assist that activity, EPA and the States designated air quality maintenance areas. Air quality planning is to be performed to insure maintenance of standards in these areas throughout a 20-year period. The potential energy development plus the attendant urban growth must be a factor in this planning activity. In order to augment State program efforts funds have been provided to assist the States in these planning efforts.

I feel strongly that State and local government must play a major role in developing environmental management programs for energy impacted areas. In addition to providing assistance for 208 and AQMA planning, I have taken several other steps to help local governments prepare for changes. We are taking an active role in providing technical and planning assistance to State and local government. We are also participating in joint Federal/State programs such as the Oil Shale Environmental Advisory Panel and the Yellowstone Level B Study. Another area of EPA investigation is one related to community assistance programs. This subject is of major importance to the people in the potential energy development communities.

One project will survey and identify community drinking water facilities and needs in several oil shale impacted communities. Another project will aid Colorado communities in establishing comprehensive noise control programs. A third project will result in the preparation of a handbook designed to be used by local decisionmakers, such as mayors and city managers. This handbook should serve as a guide to successfully prioritizing and handling the problems of community growth and environmental management. A listing of alternative methods of wastewater treatment along with costs and sources of funding will be one of the project outputs. Another EPA-funded project will address the public services needed for rapid growth communities. Community surveys will be conducted in order to gather information on communicable disease, accidents, etc., and their possible link to environmental degradation.

Region VIII EPA is not involved in long-term research projects; we depend upon EPA's Office of Research and Development for this contribution. Our efforts are short term and focused on describing baseline conditions of environmental quality, prediction of environmental impacts, and evaluation of abatement and control options. Nationally, Congress set aside $134 million in FY 76 for interagency energy and environmental research. Another $100 million has been earmarked in FY 78. EPA is acting as the coordinating agency for these funds which will be channeled to EPA, ERDA and 16 other Federal agencies.

A vast amount of EPA's resources are being channeled into the mitigation of environmental impacts of energy development. The research, planning, monitoring, and community assistance programs are funding over $18 million dollars worth of projects in, or related to, the impact areas. Of this $18 million, $11 million has been designated by the Office of Research and Development for western energy-related problems, $4 million for section 208 funding, and the remaining $3 million for our Region VIII office of energy activities.

More specifically, we are looking at the origin and fate of trace elements from coal combustion, air- versus wet-cooling technology, water conservation and utilization, and problems with disposal of spent oil shale, fly ash, slag and scrubber solids. We are characterizing emissions from coal gasification and oil shale plants.

In conclusion, I would emphasize the need for communication among all involved entities. Federal, State and local government must work hand-in-hand with industry and the public. Viewpoints of citizens, citizens' groups, and representation, such as the Councils of Government must be solicited.

The American people—and particularly here in the west—are committed to environmental protection and progress. We are willing to commit ourselves to the mining and burning of greater amounts of coal, but not at the price of continued danger and damage to our health and our environment. We want, and the Nation needs, an adequate supply of energy at prices we all can afford. We are willing to trade higher electric bills for lower doctor bills and lower levels of pollution and environmental damage. We can burn coal and breathe clean air as well. We can mine coal in ways that will not undermine the quality of our lives and the distinct character of our region. We can commit ourselves to coal, if we are willing to do it in ways that are humanly safe and environmentally sound.

4 November 1975

Session III (con.):

## RETROFITTING OUR PRESENT-DAY ENERGY SYSTEMS

Roger S. Carlsmith
Session Chairman

# ENERGY CONSERVATION TECHNIQUES APPLICABLE TO THE IRON FOUNDRY'S CUPOLA

Dennis J. Martin[1]

### *Abstract*

*The cupola is the device most often used—primarily due to economic factors—for the melting of gray iron. Two events in recent years, however, have caused significant difficulties in the use of the cupola. The first event was the Clean Air Act, which promulgated an avalanche of air pollution regulations. The second event was the substantial increase in fuel prices usually associated with the OPEC embargo. Added to these is the energy wastefulness of the cupola. All three problem areas are now part of the difficulty involved in running a successful and economical cupola operation. There do exist technologies to partially alleviate all three problem areas; this paper concerns the results of an investigation into the feasibility of these technologies.*

## ENERGY WASTE

The cupola is simply a device for melting iron to a specific chemical composition and to a specific temperature. The physical characteristics of conventional type cupolas are shown in figure 1. In preparation for melting, the bottom doors of the cupola are propped shut and a layer of sand up to 10 inches in depth placed above them up to the iron tapholes. Next, a layer of coke is placed on top of the sand. This layer is then ignited, usually with natural gas, and more coke is added to a specified height above the cupola's tuyeres. Alternate charges of coke (mixed with a fluxing agent) and iron are then fed into the cupola through the charging door.

Combustion air is forced into the cupola through the tuyeres. The heat generated by combustion melts the iron charge and the molten metal flows through the coke layers to the sand bottom, where it can be tapped. For an in-depth explanation of cupola operating practices, the reader is referred to the manual entitled "The Cupola and Its Operation" prepared by the American Foundrymen's Society.

The cupola is an energy intensive device with over 60 percent of the heat generated being exhausted to the atmosphere. For any good foundry operation, an energy balance should be constructed. The procedure for doing such, while somewhat involved, lays the basis for the correct understanding of the cupola. An example of the results of a heat balance can be found in table 1 for a cupola with such operating conditions as those listed in table 2.

Two other energy inputs to a cupola system that are not usually considered are fan horsepower and afterburner requirements. These would usually add 8 to 10 million Btu per hour to the energy input.

## ENERGY WASTE – TECHNOLOGICAL SOLUTIONS

### *Recuperative Heat Exchangers*

From the heat balance it is obvious that a majority of the energy input to the cupola is wasted in the stack exhaust. The most economical and useful method of recovering some of this energy is by the use of a recuperative heat exchanger. The heat recovered is then returned to the cupola in the form of a hot blast. A schematic

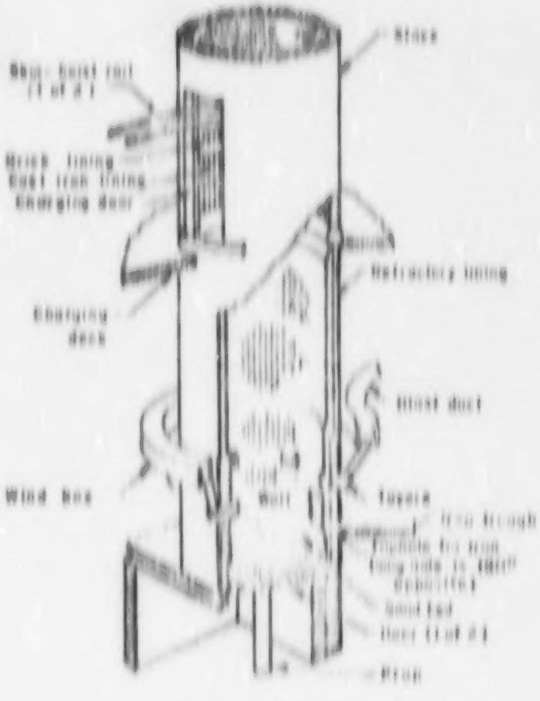

Figure 1. Illustration of conventional lined cupola (ref. 1).

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Table 1. Heat balance of cupola

| | | |
|---|---|---|
| **Heat input** | | |
| 1. Potential heat from coke | 67,595,017 | Btu/hr |
| 2. Carbon loss from dissociation | 5,751,896 | " |
| 3. Carbon loss from iron pickup | 3,873,136 | " |
| 4. Oxidation of iron | 111,480 | " |
| 5. Oxidation of manganese | 405,216 | " |
| 6. Oxidation of silicon | 735,840 | " |
| Total heat input | 79,222,521 | " |
| **Heat output** | | |
| 1. Iron | 31,326,180 | Btu/hr |
| 2. Slag | 2,824,012 | " |
| 3. Dissociation | 1,733,044 | " |
| 4. Stack gas sensible | 10,686,368 | " |
| 5. Stack gas latent | 30,303,364 | " |
| 6. Radiation from cupola | 2,349,553 | " |
| Total heat output | 79,222,521 | " |

of a typical recuperative hot blast system can be seen in figure 2. Air to the cupola can be preheated to 1,200° F, which can account for a maximum of 30 percent of the energy in the stack gas of a medium-sized cupola.

There are several possible variations of the normal recuperative system. Generally the takeoff point to the afterburner is located adjacent to or above the charge door and is commonly referred to as "above charge door takeoff." This positioning allows enormous quantities of tramp air to infiltrate the system. "Below charge door takeoff" normally has the flue gas being drawn off from 4 to 6 feet below the top of the charge material. Infiltration is usually cut in half. A relatively new variation is to increase the amount of charge material to the point where the flue gas takeoff is below approximately 25 feet of charge. This reduces infiltration to zero and allows cleaning of the flue gas prior to afterburning. Care must be taken that air does not enter into such a system to avoid a CO or $H_2$ explosion.

While recuperative heat exchangers are not a new idea, it has only been recently that design problems caused by high particulate grain loading and temperature have been overcome. As of yet, however, there are only 30 recuperative systems installed on iron foundries in this country. Our investigation has shown that the equipment on the market exhibits a high degree of reliability. The system that utilizes particulate removal prior to afterburning has not yet become operational but is expected to in the near future.

### *Other Waste Heat Uses*

While there are numerous other possibilities for waste heat recovery, the dominating factor is the plant layout. One foundry was able to utilize the stack gas waste heat for plant heating but only because the necessary duct work was already in place near the recuperative heat exchanger. Other possible ideas, such as sand or coke drying, depend upon the proximity of the drying

Table 2. Cupola data

| | |
|---|---|
| Charging rate lb/hr | 56,000 |
| Coke rate lb/hr | 6,588.2 |
| Limestone rate lb/hr | 1,120 |
| Blast volume ft$^3$/hr | 678,000 |
| Blast temperature, °F | 70 |
| Tapping temperature, °F | 2,762 |
| $CO_2$ content of stack gas, percent | 12.00 |
| CO content of stack gas, percent | 14.9 |
| Dry bulb temperature of blast air | 70 |
| Wet bulb temperature of blast air | 68 |
| Barometric pressure | 29.92 |
| Stack temperature, °F | 900 |
| Tapped iron | |
| -Carbon content, percent | 3.0 |
| -Silicon content, percent | 0.60 |
| -Manganese content, percent | 0.48 |
| Charged iron | |
| -Carbon content, percent | 2.52 |
| -Silicon content, percent | 0.70 |
| -Manganese content, percent | 0.72 |
| Slag | |
| CaO content, percent | 22.00 |
| FeO content, percent | 2.5 |
| $CaCO_3$ content of limestone | 98 |
| Fixed carbon content of coke | 92 |

facility to the cupola. One idea that has been brought up, but not put into practice, is drawing off a portion of the CO-laden air before the afterburners and piping this to the drying facilities. The obvious difficulty in doing this is preventing an explosion from occurring due to the CO and $H_2$ present. This is possible to circumvent, however, if infiltration through the charge door is completely eliminated and there is no oxygen in the system.

An ambitious scheme to produce electricity from the waste heat has also been proposed. This does not appear justifiable from an economic viewpoint. The steam produced from a waterwalled combustion section, however, can be used to drive the ID fan and the combustion air fan economically.

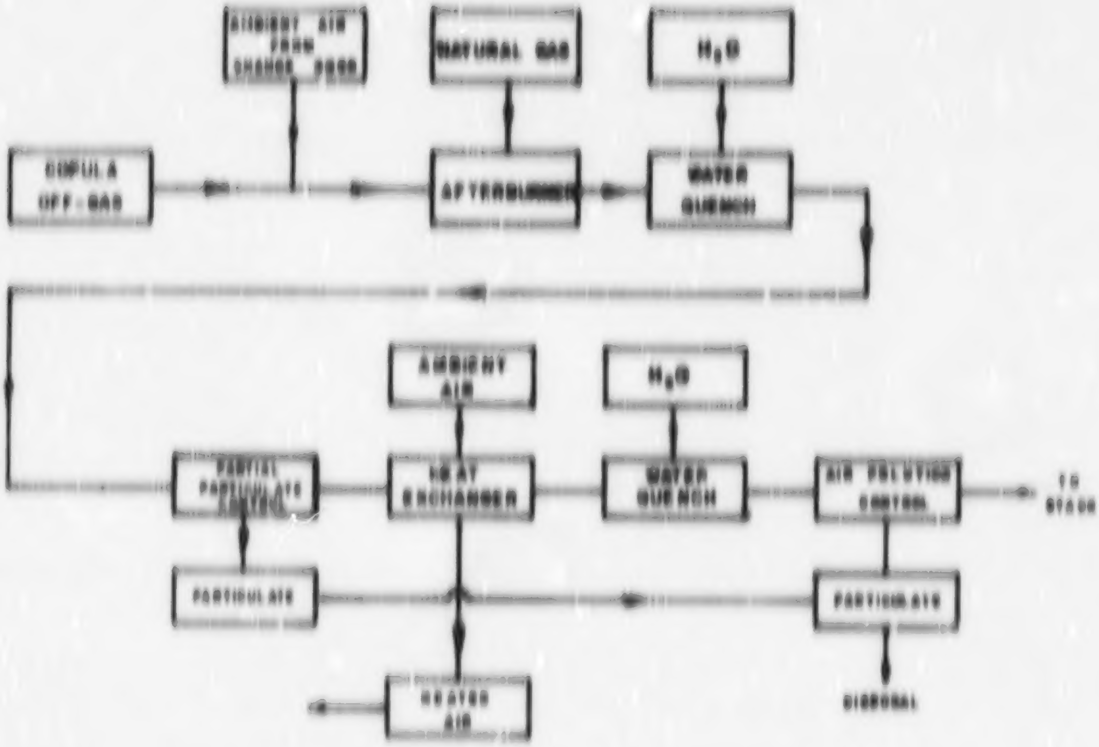


Figure 2. Schematic of heat recovery system.

## AIR POLLUTION CONTROL

Air pollution regulations are necessary to preserve the health and well being of our population. The regulations, though, have caused major difficulties for the foundry industry due to the fact that the emissions from a cupola have inherent properties which make the emissions difficult to control. The particulate grain loading in a cupola's exhaust is very high. To control this within acceptable limits, a pollution control device must be highly efficient (usually an efficiency of 98 percent removal is the minimum required, while a removal efficiency of 99 percent is common). This efficiency requirement limits the choice of control equipment to three devices; namely, electrostatic precipitators, high energy scrubbers, and baghouses.

The particle size of the dust emitted from a cupola is also a factor in control device selection and design since an appreciable percentage is usually below 10 microns in diameter (see table 3). This results in the necessity of a pollution control device not only with a high overall efficiency but also with a high collection efficiency for small particles.

Finally, the exhaust gases from a cupola have an appreciable carbon monoxide content, usually averaging around 13 percent. To comply with air pollution codes that severely limit the amount of carbon monoxide emitted to the atmosphere and to avoid the possibility of explosions in the ductwork, the exhaust gases are afterburned to convert the CO to $CO_2$. The temperature of the exhaust gas is therefore usually in the range of 2,000° F by virtue of the CO combustion. This temperature is, of course, far above what any pollution control device can handle and consequently must be reduced. The two most common methods of accomplishing this are dilution with ambient air and water quenching. Both of these methods, however, present further problems. While diluting with ambient air is an effective method of reducing the exhaust temperature, it also significantly increases the gas volume through the system. Since the cost of pollution control equipment is directly related to the air volume to be treated, this method would result in a large cost increase. Water quenching systems, while effective to a degree, are not useful in reducing the exit temperature by more than about 500° F. Water quench systems are also frequently undersized such that not all

Table 3. Particle size distribution — cupola emissions
(ref. 2)

| Plant | Cumulative percent by weight, diameter in microns | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | <1 | <2 | <5 | <10 | <20 | <50 | <100 | <200 |
| 1 | | 30% | 50% | 65% | 82% | 90% | 99% | |
| 2 | | 64 | 82 | 98 | 99 | | | |
| 3 | | | 2 | 12 | 34 | 92 | 99 | 99% |
| 4 | | 13 | 28 | 45 | 55 | 60 | | |
| 5 | | | 54 | 86 | 98 | 99 | 99 | 99 |
| 6 | | | 14 | 15 | 15 | 21 | 99 | |
| 7 | | | | | 19 | 25 | 99 | |
| 8 | | | | | | 99 | 99 | |
| 9 | | 0.6 | 2 | 3 | 8 | 99 | 99 | |
| 10 | | | 4 | 5.5 | 7 | 13.7 | 75 | 80 |
| 11 | | | 11 | 13 | 32 | 53 | 75 | 94 |
| 12 | | | 8 | 12 | 17 | 28 | 69 | 89 |
| 13 | | | 18 | 25 | 38 | 62 | | |
| 14 | | | 17 | 26 | 36 | 53 | | |
| 15 | | | 24 | 28 | 23 | 42 | | |
| 16 | | | 26 | 30 | 32 | 44 | | |
| 17 | 0 | 7 | 25 | 32 | 34 | 41 | 56 | 61 |
| 18 | 0 | 7 | 24 | 41 | 47 | 32 | 69 | 81 |

of the water flashes into steam. This excess water causes damage to the refractory and ductwork. If a baghouse is used after a water quenching system, cool spots in the baghouse could allow condensation of the water vapor on the bags. This increases the weight on the bag, causing caking and bag failure. Due to the aforementioned reasons, neither system is used exclusively but rather a combination of the two techniques is employed.

With the necessity of employing a highly efficient pollution control device that incorporates a temperature reduction mode, the cost of such a system becomes an important consideration to the foundry management. Table 4 shows the economics of air pollution control for the three most prevalent devices. As noted, the cost of any pollution control device is dependent on flow. Using ambient air as a temperature controller can increase the flow by a factor of 4 and above. The cost of controlling the pollution from a large cupola runs into the millions of dollars. Costs for smaller cupolas are often in the neighborhood of $1 million.

Table 4. Cost equations (ref. 2)

| Equipment type | Investment cost equation | Limits of observation | Correlation coefficient | F ratio | Standard error | Data points |
|---|---|---|---|---|---|---|
| High energy wet scrubber | I=49,519+2.84 gas vol | 6,000 gas vol 20,000 | .82 | 25 | 16,000 | 25 |
| | I=43,519+0.97 gas vol | 20,000 gas vol 92,000 | .99 | 139 | 29,000 | |
| Low energy wet | I=38,744+2.05 gas vol | 4,500 gas vol 67,000 | .84 | 55 | 22,000 | 34 |
| Fabric filter | I=-55,000+8.95 gas vol | 10,800 gas vol 100,000 | .98 | 321 | 48,000 | 19 |

## AIR POLLUTION CONTROL — TECHNOLOGICAL SOLUTIONS

### *Recuperative Heat Exchangers*

As noted previously, one of the more innovative systems proposed for recuperative heat exchanging inherently reduces the cost of air pollution control. In this section the cupola is top loaded and the depth of the charge material is approximately 25 feet above the flue gas takeoff point. Infiltration is effectively reduced to zero. The flue gas is immediately quenched to about 180° F and then scrubbed for particulate removal. The gas is then afterburned to recover the latent heat. The primary advantage to this system is that the volume of gas to be cleaned is at least one fourth of the volume of conventional systems, and the cost of pollution control is appreciably reduced.

Ordinary "below charge door takeoff" is also effective in reducing gas volumes to be treated by approximately 50 percent, thereby reducing air pollution cost. This alone is an appreciable improvement over existing systems.

### *Steam Hydro Air Cleaning System*

This system solves two problems simultaneously. It is a low-cost pollution control device of high efficiency and is run by waste heat from the cupola. The flue gas from the afterburner goes to a waste heat boiler. Steam produced creates the draft that draws the dust-laden air into the system. The steam is injected into a mixing tube, and encapsulation, nucleation, droplet growth, and massive turbulent scrubbing takes place. The particulate can then be removed by low-pressure drop cyclones. Efficiencies for the device are above 99 percent and since the draft is induced by the steam there are no horsepower requirements. The system can also be adapted to use the steam for other purposes. Startup problems can be eliminated by using a steam-driven compressor to store compressed air, which the system can use instead of steam for pollution control.

## FUEL COST

The cost of coke has risen from $44.00 per ton in 1971 to $112.00 per ton in 1976. Deregulation of oil prices will probably increase this somewhat more. The increased emphasis on the use of coal as a fuel and the environmental regulation governing stripmining operations will further tend to increase coke prices in the years ahead. Such fuel price increases, if continued, would make cupola operation uneconomical.

## FUEL COST — TECHNOLOGICAL SOLUTIONS

### *Recuperative Hot Blast*

The major benefit of hot blast is a reduction in coke consumption. The relationship between the degree of preheat and coke reduction is shown in Figure 3 (ref. 3). Converting from a cold to hot blast usually conserves about 25 percent of the coke. For a 30 ton/hour cupola, this could result in $600,000 saved per year. Also, since the emissions from a cupola are dependent on the amount of coke used, the efficiencies required for pollution control devices are reduced.

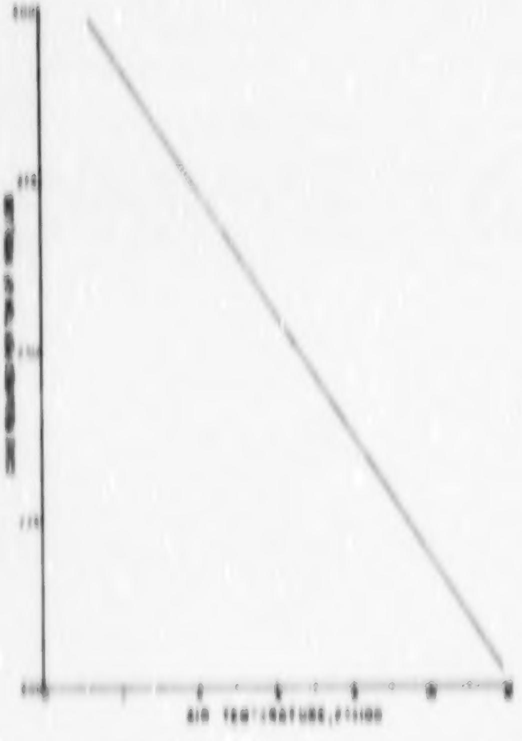


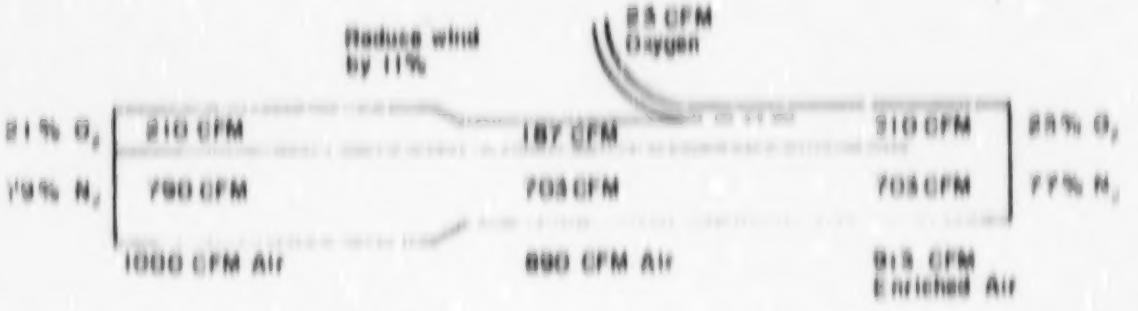
Figure 3. Effect of hot blast on coke.

*Divided Blast*

The concept of introducing blast air into the furnace through a double row of tuyeres has been around for some time. It was not until recently, however, that the control and monitoring system necessary for holding the blast rate balanced have become available. The use of a balanced blast on cold blast cupolas has been credited with fuel savings of 20 to 25 percent of the coke. Operations in this country have been less successful since the practice has been to have only one control system and windbox. In Canada, where the divided blast has been used successfully, the practice has been to use separate windboxes and controls for both rows.

*Oxygen Enrichment*

By increasing the flow of air to the cupola, the rate of combustion of the coke is increased. The use of pure oxygen added to the combustion air allows for an increase in melting rate without appreciably increasing the air volume. This effect can be seen in figure 4. Using a 2 percent enrichment, the air volume necessary for the same equivalent air is reduced by 8.7 percent. Higher flame temperature and a reduction in the oxidation zone results along with a decrease in the amount of nitrogen supplied to the furnace. Using a 3 percent oxygen enrichment, coke reductions of 10 to 20 percent are possible, depending on the foundry. The cost of the oxygen, however, reduces the cost benefits of reduced coke consumption.



$$\frac{\text{210 CFM OXYGEN}}{\text{915CFM Enriched Air}} = \text{23\% or 2\% Enrichment}$$

Figure 4. Equivalent enrichment.

Courtesy of Air Products and Chemicals

## SUMMARY

Our investigation has shown that the technologies exist for foundries to economically combat pollution while conserving energy. Different strategies, however, must be adopted for different situations. A new plant should have a layout that would maximize the use of recovered heat. Existing plants must decide which technology would give the most economic benefit. For instance, a plant with a cold blast and an adequate pollution control system would benefit the most by simply converting to divided blast, which is a relatively low-cost technique but one which yields an appreciable economic benefit.

Perhaps the most important aspect of these technologies is that the small foundry operator now has some cost-effective techniques that may be employed to compensate for the spiralling raw material costs and increasingly stringent pollution control standards that have been threatening to force him out of business.

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# ENERGY USE, EFFICIENCY, AND CONSERVATION IN INDUSTRY

Robert H. Essenhigh, Ph.D.[*]

## *Abstract*

*Energy conservation can reduce pollutant emissions, reduce pressure on energy sources, and possibly reduce manufacturing costs. The basis for energy savings campaigns must be: first, knowing current consumption and efficiencies of use; and second, having targets of consumption and of use efficiencies for comparison. Current use is determined by energy audits. Target use is determined on the basis of several factors, including thermodynamic considerations. Furnace Analysis also provides a basis for identifying the principal factors controlling efficiency of furnaces; factors include output, excess air, processing temperature, etc. In evaluating and comparing systems and tasks, four efficiencies and three efficiency ratios are involved: the operating efficiency of the system* ($\eta$)*, its intrinsic efficiency* ($\varepsilon$)*, its maximum efficiency* ($\eta_{max}$)*, and the maximum task efficiency* ($\eta^0_{max}$) *of the optimum system for the task; the efficiency ratio of the system* ($r_s = \eta/\eta_{max}$)*, the efficiency ratio for the task* ($r_T = \eta/\eta^0_{max}$)*, and the figure of the merit for the efficiency of the system at its optimum efficiency* ($r_{ST} = \eta_{max}/\eta^0_{max}$)*. The task efficiency ratio* ($r_T$) *is shown to be identical or nearly identical to the so-called "Second Law" efficiency. Evaluation of the material deployed in terms of efficiencies and the Furnace Analysis performance equations provides a basis for developing a systematic energy savings procedure. However, in spite of low overall efficiencies (25 to 35 percent) in the industrial sector of the energy market, where potential for savings exists, it is nevertheless concluded that the chief barrier to more rapid progress in energy conservation is out-of-date or invalid cost accounting procedures.*

## INTRODUCTION

It is a truism that, if pollution emissions at any moment in time are roughly proportional to energy use, conservation of energy will greatly aid pollution control. This is well recognized, but it has waited for the developing energy famine to provide the incentive for action that will reduce pollutant emissions by this means. Energy conservation indeed serves several joint interests. It can reduce pollutant emissions, reduce pressure on energy sources and—sometimes—reduce manufacturing costs. These triple objectives deserve more emphasis. This paper will therefore focus on conservation, particularly in the industrial sector of the energy market. This particular sector has been chosen as the one that uses the most energy, while at the same time it contains the most diverse array of energy applications and yet has had the least attention.

## THE SCOPE FOR CONSERVATION

The starting point is, clearly: What is the scope for conservation, and where does the energy go?

As a basis for the initial answers to these questions, figure 1 illustrates the energy flow in the United States in 1970 in the form of a Sankey or energy flow diagram (ref. 1). This particular diagram has been reproduced many times in the last few years, but it is reproduced here once again to emphasize two points. The first point is the small magnitude of energy supplied by electricity to end use; and the second point is the magnitude of waste, and the implied inefficiencies of use, in this modified diagram.

Taking first the matter of energy supply by electricity, the fact that this intermediate conversion market of electricity generation draws on 25 percent of all gross energy supplies and operates at an overall efficiency of approximately one-third is well known and has been very widely quoted. The consequence of waste, however, has not been so fully emphasized with respect to the relatively small magnitude of energy flow to end use. As the diagram shows, in the year 1970 this amounted to about 8 percent of gross energy flow in the system. The percentage of energy delivered by electricity to end use is, therefore, 8 parts in approximately 72, which is about only 10 percent of total end use demand. The point is emphasized because of the feeling that still seems to exist among many people that with the development of nuclear fission or fusion power systems, all problems will ultimately be solved, and there will be no further energy worries. It should be noted, however, that even if the expected increase of nuclear production of electricity is attained, and by the end of this century electricity will draw on a gross of 50 percent total energy supplies, it will still only deliver about 25 percent of end use requirements, of which approximately 10 to 15 percent will be derived from nuclear sources. This means that we shall still have to rely on fossil energy sources even by

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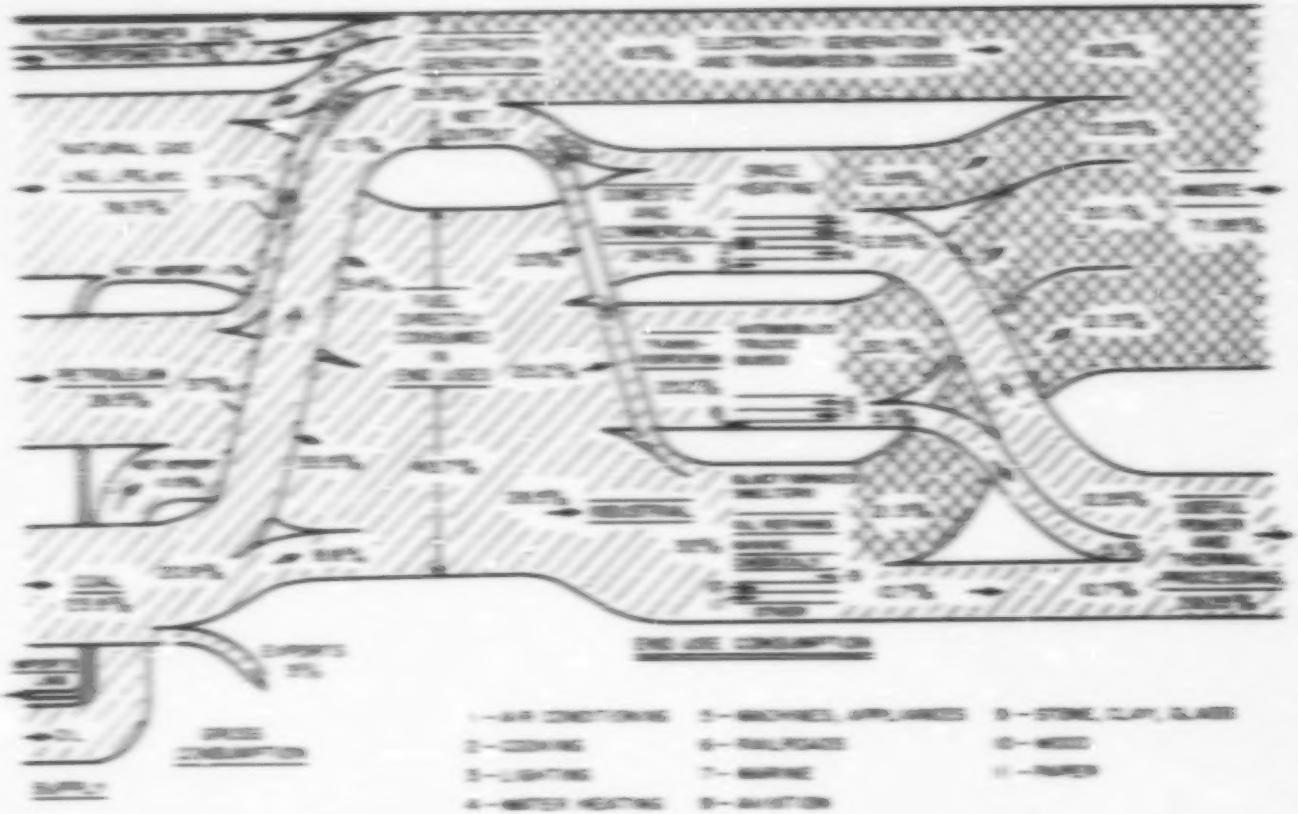
NUCLEAR POWER
HYDROPOWER
ELECTRICITY GENERATION AND TRANSMISSION LOSSES
NATURAL GAS
PETROLEUM
COAL
OIL
SUPPLY
GROSS CONSUMPTION
EXPORTS
FUEL DIRECTLY CONSUMED IN END USES
DOMESTIC AND COMMERCIAL
TRANSPORTATION
INDUSTRIAL
SPACE HEATING
WASTE
USEFUL WORK AND THERMAL PROCESSING
END USE CONSUMPTION
1—AIR CONDITIONING
2—COOKING
3—LIGHTING
4—WATER HEATING
5—MACHINES, APPLIANCES
6—RAILROADS
7—MARINE
8—AVIATION
9—STONE, CLAY, GLASS
10—WOOD
11—PAPER

Figure 1. ENERGY FLOW IN THE UNITED STATES IN 1970. (Adapted from Earl Cook (ref. 1). Figures are percentages of gross domestic consumption (i.e., less exports) adopting use efficiencies as follows: (1) electricity generation, 31 percent; (2) domestic and commercial, 50 percent; (3) transportation, 20 percent; (4) industrial, 33 percent. Gross domestic consumption: 64.6x10$^{15}$ Btu per year = 2.2x10$^{12}$ wt.

the end of this century for 80 to 90 percent of energy supply to the end use markets. This reemphasizes the critical dependence that we shall still have on fossil energy by the year 2000, and the strong need to implement all conservation practices as soon as possible. Coupled with the assumption of a still rising GNP over the next 25 years, the absolute fossil fuel requirements will likewise be rising, and the need to conserve fuel just to control pollutant emissions becomes imperative.

The second point regarding efficiencies of use is, therefore, even more significant. Commonly the energy flow diagrams published elsewhere have shown approximately 50 percent of total energy going to waste. In figure 1, this is increased to a little over 70 percent. The two main changes have been: reduction of space heating from about 75 percent overall efficiency to 50 percent; and, even more drastically, a reduction on the industrial sector of about two-thirds overall efficiency to about one-third (which may still be high). This really targets the objective of this paper. It is to explore the sources of inefficiency of energy use in industry, and to develop a set of priorities for action in conservation efforts.

Industrial energy use, overall, accounts for about 40 percent of total energy use, of which roughly 12 percent is used for generating the electrical requirements which delivers nearly 4 percent (as electricity) for use. The remaining 28 percent is energy nominally delivered as raw fuel to end use. This energy supply is delivered to four subsectors. These are process steam, raised in boilers; process heat, used in industrial furnaces; electric delivery, which is mainly electric drive; and feedstock, which is quite minor. As can be seen from table 1, showing the breakdown in percentage of industrial use, process heat accounts for about one-third of all use, and process steam nearly half. The problem of efficiency exists only to a minor degree in the steam raising process itself, because the boilers are overall respectably efficient if properly designed, specified, maintained, and operated. The inefficiencies of industrial use come about firstly, in the use of the steam in the varied processes; and secondly, in the direct-heat use in the process furnaces. This article will focus mainly on the process furnace subsector, which parenthetically will include the problem of steam use in appropriate process operations. The nature of the problem is that this process furnace subsector is seen as a multitude of dissimilar functions because of the significant differences of equipment, operation, control, end products, and so forth. This subsector therefore lacks the common unity found in steam raising, or in transportation, or electric generation, or domestic and commercial space heating. It is therefore claimed that argument from one industry or company to another is invalid. One of the points to be made in this article is that, contrary to general belief, the very wide range of process furnaces can nevertheless be treated largely as a single subset entity.

## EFFICIENCY OF THERMAL SYSTEMS

The basis of efficiency analysis is the heat or energy balance, which in principle is simple enough. In practice, however, there are a number of subtleties that have caused considerable confusion in the past, and would appear to be continuing to do so. The sources of part of

Table 1. Energy use in industry

| | Percent of gross national use | Percent of net industrial use |
|---|---|---|
| Process steam (boilers) | 16.5 | 48 |
| Process heat (furnaces) | 11.5 | 33 |
| Electricity (gross) | 9 | |
| (net delivered) | 4 | 9 |
| Feedstock | 3.5 | 10 |
| Total | 40.5 percent | 100 percent |

the confusion appear to be the methods of using the laws of thermodynamics and the sometimes conflicting requirements of dynamic behavior. This section will present a specific view of efficiency that may be at variance in some respects with some other presentations of this subject.

### *Objectives of Efficiency Analysis*

The objectives of efficiency analysis are essentially practical: they are to determine the energy flows in a system, and from that to determine the scope for energy savings. There are two ways in which this can be accomplished. The first is to examine a system in use and to determine the scope for upgrading its efficiency; and the second is to investigate the scope for substituting a different energy supply system which may even involve a different way altogether of achieving the same end objective.

In the first approach it is necessary, as strongly emphasized by Lyle (ref. 2) nearly three decades ago, to determine the actual use, or efficiency, and to compare this with some target use or efficiency. The development of targets is therefore central to any effective energy analysis intended for practical action: this article therefore focuses also on the method of developing such targets.

Upgrading the system can include rearrangement of existing pieces of equipment: for example, the rearrangement of a production line which, as actually carried out in one instance, eliminated two reheat furnaces.

The second approach is to investigate the scope for using some method of upgrading the heat and fundamentally changing the heating system. Again reference can be made to Lyle (ref. 2a) for an early discussion on the scope for doing this by use of heat transformers.

The role of thermodynamics in these procedures is, first, to aid the development of the heat balance, utilizing the First Law; and second, to utilize the Second Law for investigating the scope for upgrading the heating systems themselves. These points will be amplified below.

### *Definition of Efficiency*

Efficiency is something of an intuitive concept. The most general definition is: the ratio of useful return on input. In the context of thermal processing, the useful return can be measured by the energy in the product, and input is measured by total Btu's supplied by fuel or any other energy sources. Most commonly it is expressed by the following equation:

$$\text{Efficiency} = \frac{\text{Useful output, in energy units}}{\text{Total input, in energy units}}$$

Values of efficiency mostly lie below 100 percent. Where efficiency exceeds 100 percent it is common to divide the efficiency by 100 and rename it Coefficient of Performance (a procedure described by Lyle (ref. 2) as cowardice!). An alternative specification commonly found in industry is essentially the reciprocal of efficiency: Btu per unit of product. As this is reduced, the process is more efficient. This is also known as the "Specific Energy Consumption."

It must be emphasized that efficiency is the ratio of a part to the whole. Since selection of the part involves a value determination of what is useful, this means that efficiency is essentially a value judgment, and, as such, it is neither a scientific concept nor is it a thermodynamic function in spite of the central place that efficiency plays in part of classical thermodynamic theory. Efficiency must be defined on a clearly specified device, in a precisely specified function. Since efficiency is a value judgment, its numerical magnitude can be changed by changing one's mind. For example, a heat engine working as a heat pump has one efficiency, but the same device working as a refrigerator has a different efficiency. What has happened here is no change in the device, but a change in the specified function. In discussions of efficiency, it is sometimes found that devices are compared while changing the ground rules, and invalid conclusions are obtained. Nature, however, has no concern for efficiency: all energy is utilized by nature in its own way, and the concept of value has no meaning. Moreover, two different living systems can very well place different values on different components of energy supply. Consequently, two such different living systems could produce significantly different conclusions about the magnitude of efficiency. These strictures, however, do not necessarily apply when calculating the *maximum* possible energy obtainable from a given device or required for a given task. Such cases are governed by natural laws, which properly introduces thermodynamics and kinetics.

### *Thermodynamic Aspects of Efficiency*

Thermodynamics enters efficiency analysis in three principal ways. First, the First Law provides the basis for the energy balances; second, the First and Second Laws can be used to provide bases for constructing target efficiencies; and third, the Second Law can be used to identify thermodynamic sources of inefficiency, in contrast to operational sources of inefficiency.

The First Law energy balance provides the essential basis for checking the accuracy of numbers to be used in the efficiency calculation, and in that sense it is also the basis for the efficiency calculation. On that account, the efficiency as defined by equation 1 is often called the First Law efficiency, but this writer considers such a name to be misleading as it could imply that *selection* of the numbers to be used in the efficiency calculation is governed by the First Law, which of course is not so.

The First and Second Laws are used to provide a basis for constructing target efficiencies for different systems. This requires the division of all thermal processing devices into three subsets, as follows:

1. First Law limited system: process furnace, involving heat to heat conversions.
2. Second Law limited systems: power devices, involving heat to work conversions.
3. Combined heating and power where the maximum efficiency is still First Law limited, unless a heat transformer is involved (ref. 2a).

The distinction between the first two subsets is whether the device is a heat to heat conversion system or a heat to work conversion system.

The target efficiency of power systems is well known, with a long history, being nominally determined by the Carnot efficiency. Less well known is the available heat[1] limitation for the process furnaces. Targets may be specified as follows:

1. For First Law limited devices, the maximum or target efficiency is equal to the available heat, using the processing or stock temperature as the limiting temperature. The available heat is the heat in the thermal supply (or flame), at the specified temperature of the thermal supply, in excess of the processing or stock temperature. This can be written approximately:

$$\text{Efficiency, } \eta_{max} = (T_{ad} - T_s)/(T_{ad} - T_0) = \eta'' \qquad (2)$$

where $T_{ad}$ is the adiabatic flame temperature, or the temperature of the thermal supply; $T_s$ is the stock or processing temperature; and $T_0$ is the ambient temperature. Equation 2 is an approximation, but it is adequate for our purposes here; it represents a linear decline in efficiency with increasing $T_s$. In practice, the line is slightly curved, as explained (with example) below.

2. The Second Law efficiency is given by the classical Carnot efficiency equation:

$$\text{Efficiency, } \eta_{max} = 1 - T_0/T \qquad (3)$$

where T is the source temperature for the engine. In passing it may be noted that the conventional proof of Carnot's theorem, stating that all reversible engines have the same efficiency and that no engine can have efficiency greater than the Carnot engine, is essentially spurious (ref. 3). The conventional proof utilizes two engines driving each other alternately forward and backward, but exchanging heat only at the source and sink reservoirs. By exclusion of heat exchanges on the transisothermals, the transisothermals must be adiabatics. The conventional proof therefore establishes that the efficiency of the Carnot cycle is the efficiency of the Carnot cycle, and no more. Reference 3 provides the modification to the conventional proof required to recover Carnot's theorem. At the same time, however, it is also shown that there are restrictions to application of the theorem that are not normally recognized, and evidently not adhered to in practice. In particular, distinction must be drawn between the reciprocating engine, and the continuous engine in which there is also flow work. Analysis of the continuous Carnot engine shows that it has zero or negative efficiency. Use of Carnot's theorem as a basis for target efficiencies, particularly of continuous engines, is therefore cast in doubt. For the purpose of this article, however, the conventional view will be adhered to since it is appropriate in the context of this paper.

3. The use of the Second Law to identify sources of thermodynamic inefficiency, in contrast to sources of operational inefficiency provides a basis for comparing the inherent efficiency of two different systems. Operational inefficiencies, on the other hand, are concerned with the behavior of a single system under different modes of design or operation. In using the Second Law for comparisons of efficiency, what we are looking at is a comparison of the target efficiencies or efficiencies in achieving a given *task* objective by two different systems or devices. In addition, the use of the Second Law for the comparison may be pointless or inapplicable unless one or both of the devices involve engines or energy transformers. Engines convert heat to work, or vice versa. Energy transformers are devices to upgrade work or heat. Figure 2 illustrates two examples. Figure 2a is a simple work transformer, in which a system at pressure $P_0$ is able to expand and, by suitable adjustment of a fulcrum, is able to increase the pressure from $P_0$ to P. Figure 2b is a particular example of a heat transformer involving two engines, one working as an engine and the other working as a heat pump, operating between two different temperature reservoirs. This combination is not the only method of upgrading heat. Lyle (ref. 2a) list three different methods:

a. Thermocompression: steam injector, mechanical compressor.
b. Boiling point elevation.

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[1] Available heat is a combustion engineering term, not to be confused with Available Energy or Availability.

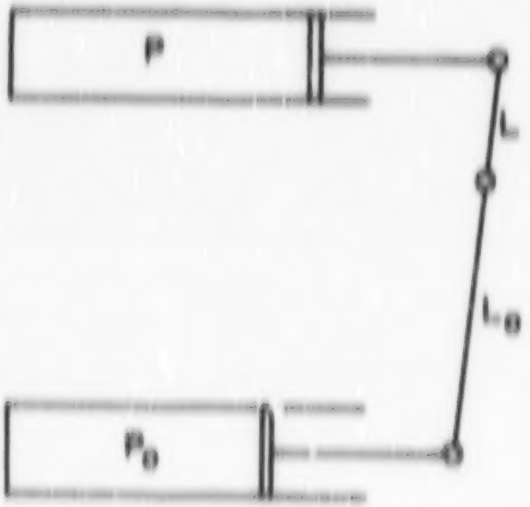

Figure 2a. The work transformer:
$p = p_0(L_0/L)$

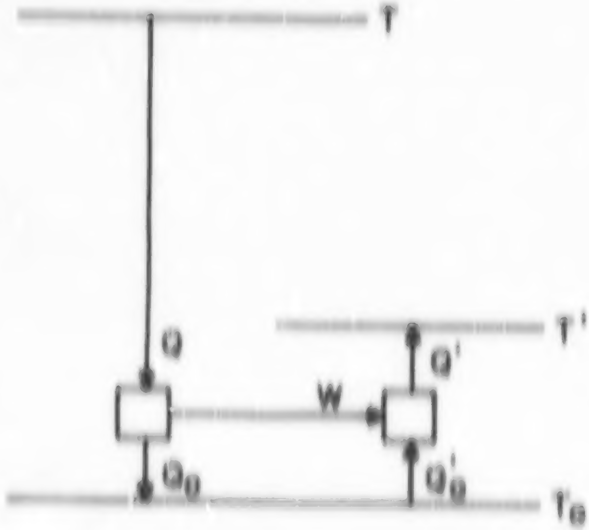
T
T'
Q
Q'
W
$Q_0$
$Q_0'$
$T_0$

Figure 2b. The heat transformer:

$$Q' = \frac{T - T_0}{T' - T_0}\, Q$$

For $T = 1{,}300$ K,
$T' = 400$ K,
and $T_0 = 300$ K,
$Q'/Q = 10$

Figure 2. Energy transformers.

c. Heat engine and heat pump combination as in figure 2b.

Of these three methods, all discussed cursorily or extensively by Lyle, the first has limited applications. The second is still evidently an untested concept, even though proposed 30 years ago. The third, however, is currently of considerable interest as a topic for analysis. The heat engine and heat pump combination is, of course, well known as a device for generating efficiencies in excess of 100 percent. As such, it is essentially a traditional subject requiring no further comment here.

Somewhat related to the heat engine and the heat pump combination is the use of a backpressure or pass-out turbine in a combined heating and power system. The common factor in the combined heating and power arrangement compared with the combined heat engine and heat pump arrangement is the thermodynamic objective to avoid useless degradation of heat. Combined heating and power is another traditional subject, also well covered by Lyle (ref. 3b); of relevance here, however, is some additional history, and additional terminology in relation to this point.

### *Efficiency Ratio and Second Law Efficiency*

The examination of the degradation of heat, and its avoidance, has generated the possibly unfortunate term of "Second Law" efficiency. It can be argued that this possibly represents a misunderstanding of the meaning and objectives of the Second Law, and its applications in this context. The older terms Efficiency Ratio or Effectiveness may be more appropriate. The use of the Second Law is to identify the system arrangement that will draw on the least amount of energy to make it work. Having done that, the efficiency can be calculated by equation 1, as before. Clearly, the practical test of any improved system is that the fuel supply will not go down so quickly for the same amount of production. Consequently, this will be accurately measured by efficiency as defined by equation 1. The effective or practical use of the so-called Second Law efficiency for choosing operational devices must provide the same result; i.e., a set of operational devices must be ranked in exactly the same order by both methods, for otherwise if they were ranked in a different order, we should be able to choose a system on the basis of a better Second Law efficiency that did in practice use more fuel. The theoretical source of concern derives from the awareness that entropy is increasing, or that energy in its flow from one system or reservoir to another is being degraded. This has, of course, been fully recognized in the case of power systems for over a century. In the case of process systems, however, where the conversions are heat to heat, the history is somewhat shorter.

The earliest paper on heat degradation in processing that this writer is aware of is that by Thring in 1943, in which he introduced the concept of the Virtue of energy (ref. 4). Examination of his analysis shows that the Virtue of energy is indeed equivalent to the net work that could be obtained from a gross amount of heat if this was utilized in a perfect cycle. As a fixed quantity of energy flows as heat through a system, but being transferred from one body to another at lower and lower temperatures, the Virtue of that same amount of energy declines progressively with temperature. The objection that can be leveled at this concept is that Virtue is then a quality attaching itself to something that only exists when it flows, namely the heat flow. There is therefore an implication that for this purpose, energy flow, and particularly heat flow, can be treated as something tangible, such as a caloric. If this identification is acceptable for purposes of argument, then the Virtue concept can be regarded as valid.

A later study on somewhat similar lines was provided by Denbigh (ref. 5), who used a Second Law analysis, again to develop a target for comparison of efficiency. This was recently amplified further by Riekert (ref. 6) (noting that he defines the normal efficiency as the First Law efficiency, and again introducing a Second Law efficiency). Similar views are taken in a study supported by the American Physical Society (ref. 7), in which a Second Law efficiency is defined, but as an operating efficiency rather than as a target efficiency. What this does, in effect, is to normalize the true operational efficiency by dividing by an optimum efficiency for the task, thus providing an effectiveness or efficiency ratio (see appendix 1).

The comparisons of appendix 1 would seem to indicate that the Second Law Efficiency must be used with care. The test of an efficiency analysis is ultimately that less fuel is used for a given quantity of product, which means that a dipstick in an oil tank, for example, will show that the level has not gone down so much. In this case, as remarked earlier, there cannot be any difference in the outcome between efficiency defined by equation 1, which is strictly a practical, operational efficiency, and in the other definitions, unless the other definitions have misleading results or are used for unintended purposes. Clearly, if the alternative definitions advise us to select systems that use more fuel, they have failed in their purpose. If all definitions lead to the same operational result, then equation 1, being the simplest, would seem to be the one to use in all operational cases.

### *Kinetic Aspects of Efficiency*

The kinetic aspects of efficiency refer to the influence of time on the efficiency. In classical thermodynamics, it is always assumed that heat exchanges have infinite time to be accomplished. Under such limiting theoretical circumstances, a source or sink can exchange heat at identically the same temperature as a body being heated or cooled. With a constraint on time, however, a temperature difference must be allowed, and it is then found in some circumstances that what is desirable for high efficiency from the thermodynamic point of view is quite the opposite from what is required from the kinetic point of view. Indeed, a key conclusion, discussed below, is that efficiency (defined by eq. 1) increases with temperature difference between the flame gases and the stock or load. It may be noted that operation in a time frame does not require any alteration to the efficiency definition as given by equation 1, even though it is no longer heat or work that is being used in a calculation but, instead, heat fluxes and work fluxes, or rates of heating and rates of working (or power). This again emphasizes that the efficiency definition used here is not a thermodynamic efficiency. It is also noted that the distinction between heat and work on the one hand, and rates of heat exchange and rates of working (or power), on the other hand, are not normally made. The distinction is being made here because, as already indicated, it has been found to be important. For that reason it seems desirable to distinguish between heat and rate of heating or process, just as a distinction is made between work and rate of working (defined as power). In this article, therefore, processing will be used as a parallel to power, to mean a rate of heat exchange. It may also be noted that, in what follows, virtually all the calculations and examples will be concerned with systems in time.

*Efficiency Ranges and Limits*

This section may be summarized by considering briefly the limits to efficiency as set by equations 2 and 3, and a brief comparison of the differences between process and power. Referring first to equation 3, this is well known, and indicates that the maximum efficiency is limited by the temperature of the source reservoir, with efficiency for a given reservoir temperature maximized by equation 3 if the exhaust to atmosphere is at ambient temperature. If the exhaust is not at ambient temperature, it is in principle possible to improve the efficiency by including a heat exchanger in some way. By contrast, although equation 2 provides something of a parallel to the Carnot efficiency limit, but for process systems, nevertheless there is still a difference in that the efficiency can be lifted, in principle, to 100 percent by suitable heat recovery equipment. Equation 2 does represent a limit to efficiency, so long as the gases leave at the processing temperature, $T_s$. Equation 2 calculates an intrinsic efficiency, representing the condition at which the maximum amount of heat goes into the stock, with minimum stack or exhaust gas loss, and no wall loss. A graph illustrating equation 2 is provided in figure 3. This will be discussed in more detail later, but it shows essentially the almost linear variation of efficiency with processing temperature for a variety of processes, with additionally the effects of excess air included, and the effect of variable specific heat (that was ignored in formulating eq. 2) also included yielding the curvature on the lines. Clearly, as processing temperature goes to the ambient, the efficiency rises towards 100 percent. (In practice, there is a break at 90 to 95 percent, on account of the loss of heat of condensation of the water from the fuel). If, however, the process temperature itself cannot be reduced to ambient, it is still possible, nonetheless, to increase the efficiency of the overall process by heat recovery. This is not indicated in figure 3; discussion of this effect is provided below.

In essence, therefore, First Law limited systems can in principle attain 100 percent efficiency on the basis of the conventional method of heating furnaces, which is direct or muffle firing; but cyclic power systems can never reach 100 percent efficiency because of the Carnot limitation (unless this is indeed avoided in special circumstances as discussed in ref. 3). When we are concerned with heat to heat conversions or exchanges, however, in the First Law limited systems, then we can, in principle, get around even the First Law limitation, if we can develop an appropriate energy transformer. The heat transformer of figure 2b will do this in principle, as it is also doing it in practice in the case of some very low temperature heating systems. What is needed for some furnace operations is a heat pump that can deliver heat at appropriate efficiency or COP, at significantly higher temperatures than have yet been achieved with heat pumps. Clearly, as T' approaches T (see figure 2b), then the value of the heat transformer progressively diminishes, partly on account of inefficiencies of the heat pump itself, with COP's significantly lower than their theoretical maxima, and also on account of the need for a significant temperature difference to enable heat to be transferred in a reasonable time. The time scales of interest can be said to range mostly between 0.1 sec and 10 sec. This will bracket the residence time of most gases in most furnaces. On account of this short residence time the temperature of, for example, a coal flame in a cold wall boiler will generally be between 2,800° F and 3,200° F while the theoretical adiabatic flame temperature is about 3,600° F, and the water walls are in the range 200° to 500° F (sometimes up to red heat, 400° C), with radiant superheaters at closer to 1,000° F. These temperature differences do, of course, represent substantial Second Law inefficiency, or virtue degradation, but they are at the same time necessary to accomplish the heat transfer within the time available. If a

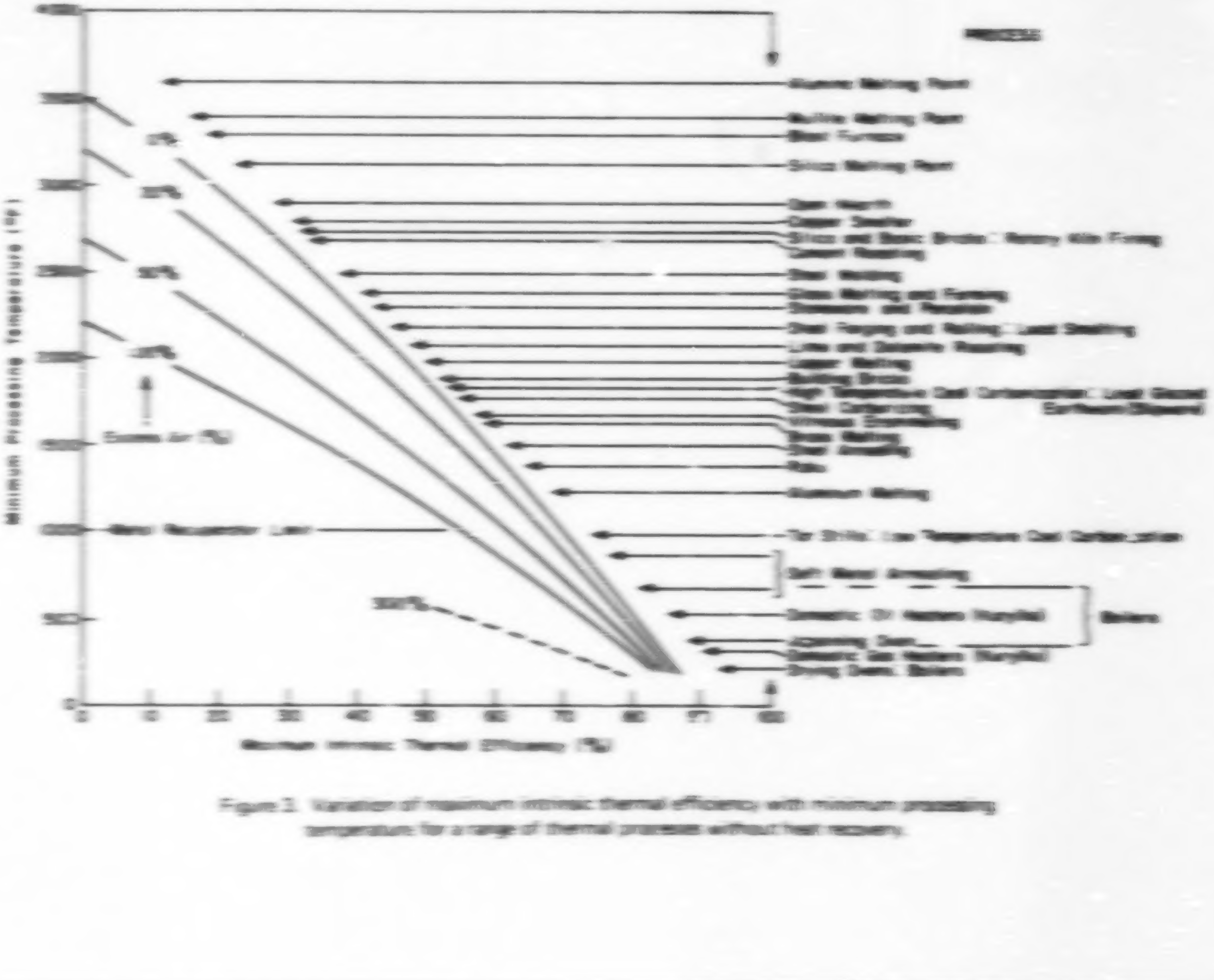

Figure 3. Variation of maximum intrinsic thermal efficiency with minimum processing temperature for a range of thermal processes without heat recovery.

1,000° temperature difference is reduced to 1° to reduce the energy degradation, the area of the heat transfer surface must be increased by 1,000 to transfer the same amount of heat in the same time. It is therefore necessary, when examining efficiency, to take into account the kinetic or time constraints as well as the thermodynamic requirements and constraints.

In summary:

1. The First Law provides the numbers for both ideal (thermodynamic) and for real time (kinetic) systems.
2. Value judgments are then used to select the appropriate numbers from the First Law balances for the calculation of efficiency using equation 1.
3. The First Law also provides the basis for evaluating target efficiencies of purely process operations. Likewise, the Second Law provides a basis for determining target efficiencies for power, combined power and heating, and heat transformer systems.
4. The ultimate basis for evaluation and comparison of different systems remains the standard efficiency calculation based on equation 1 for both ideal thermodynamic and real time or kinetic systems.

## FURNACE ANALYSIS: SUMMARY

Furnace analysis is the formal study of the development of equations for the efficiency of furnaces, where furnace includes all such thermal processing devices as boilers, stills, tanks, autoclaves, and the like. In this section the point is made first that these represent a remarkable array of diverse systems, but at the same time it is possible, as shown in the summary here, to develop a single analysis for all these diverse systems. The elements of the furnace analysis have been described in previous publications (ref. 8) which also provide details of the derivations of the equations and extensive review of other work.

### *Systems of Concern: Classification of Furnaces*

The most general furnace that can be described is a rectangular, or substantially rectangular box, of high temperature refractory brick, comprised of a roof, four walls, and a floor. This description represents quite a wide array of furnaces, particularly of the smaller processing furnaces and many heat treatment furnaces.

Variations on this basic structure are then to be found for generally good logical reasons. The essential logic of the basic construction is self-evident; variations in shape, size, and so forth are then the result of requirements in the different industries. For example, if the material being processed is a liquid, the furnace bottom must provide a bath: hence the Open Hearth furnace for steel melting and refining, the reverberatory furnace for copper, and the varied glass tanks, for example. If the material tends to be lumpy, such as in smelting, cupola melting, or lime burning, then the furnace is erected vertically, to make use of gravity for feeding the material through the furnace. At the same time, the shape changes, for obvious structural reasons, from square or rectangular cross section to circular. Additionally, if there is fear of hangup inside the vertical shaft thus formed, the walls are then flared out, as in the blast furnace for smelting (and particularly iron).

As another aspect of logical development, the roof of the typical furnace will collapse unless it is built as a sprung arch, or unless (a relatively modern development) the roof is flat but supported by an elaborate framework above the furnace roof. With the sprung arch there must be abutments to carry the thrust, and buckstays behind the abutments to prevent the abutments being pushed out, with tie bars holding the buckstays in position. If the furnace is very large, the walls themselves must be relatively thick, both to reduce wall losses and also to provide the necessary structural strength required to withstand both the weight of the roof and thermal stresses. The crushing strength, particularly of the bottom brick, must be appreciable. This generally requires high-density brick, which correspondingly tends to have high thermal conductivity. To offset the high conductivity, it is then customary to provide some degree of insulation, frequently by use of insulation brick on the outside of the furnace. Since the bricks are very expensive, it is also customary to optimize design against cost by building large furnaces with two or even three different types of brick, with the outer brick being generally the more highly insulating and with the inside brick able to stand the highest temperatures. The middle bricks are therefore often of lower quality and carefully selected so that their softening temperature will not be exceeded in the furnace as designed. Other factors that have to be considered in selection of the brick include (as well as density and thermal conductivity) refractoriness, the crushing strength, refractoriness under load, spalling, slag resistance (where this is important), and the softening temperature or melting point. Therefore, where refractories are carefully selected to meet the maximum demand on the furnace, the unthinking addition of further insulation can lead to disaster, since the internal temperatures will rise, and if they rise above the design point the furnace can collapse. If further insulation is to be added, it would be wise to recover the original design data, if these are still available, and recalculate the effect on the furnace to prevent the possibility of collapse.

It may also be noted that the wall losses through most furnace walls are 10 percent or less of the heat supplied by the fuel. This rises as the operating temperature rises, and in special cases, for example, the glass tank, it can be as high as 30 to 35 percent, where these very high values are required to maintain the refractory at a temperature below which they will not melt away or collapse. For the higher temperature furnaces the question of reducing wall losses is generally a problem of materials, not of failure to understand fundamental principles.

There are other aspects of furnaces that must also be considered: for example, furnaces are used in different ways depending on whether the material to be heated is in units, or can be treated in a continuous flow. For example, very large ingots being heated for stress relief or soaking may be held in a furnace for periods up to 3 or 4 weeks. Such furnaces are generally referred to as batch or "in and out." More commonly the batch furnaces are the smaller ones where material is being prepared in relatively small quantities or small batches. However, the ideal requirement, naturally, is to be able to process the material continuously. Glass tanks are a good example; however, many uniform solid units can also be processed continuously, such as steel billets being pushed through billet heating furnaces, or parts for stress relief, that can be glass, metal, nonmetal, etc., being carried through the furnace on conveyors.

An intermediate type of furnace is the one that is generally run over a period of months or years, such as the Open Hearth, the blast furnace, and so forth, in which the material is added in batches, processed over a period of hours, removed, and a new batch added. In the case of the blast furnace there is a steady burden moving through continuously, with material added with some degree of frequency, but slag and iron only removed by tapping at very definite intervals of several hours. On a daily basis, such furnaces appear to be batch or periodic, yet on a monthly basis, or over the period of the campaign lifetime of the furnace, the output can be treated as continuous. This is important since such furnaces can likewise be analyzed by the furnace analysis procedure, which originated with analysis of continuous furnaces.

A further aspect of furnace variation is whether the furnace is direct fired or indirect fired. If indirect fired, it is known as a muffle, and in such furnaces the combustion gases are separated from the stock being heated to prevent contamination. A typical but not unique design is the radiant tube furnace.

There are also, of course, additional furnaces whose designs depart to a minor or a major extent from the above general descriptions; for example, multiple hearth furnaces, generally used for ore roasting; or tar stills, which generally have bare metal tubes, although sometimes with refractory sections; or coal stills or coking ovens. Nevertheless, the above general description provides a reasonably common context for consideration of most furnaces. Table 2 provides a classification of many furnaces based on the primary division into batch, periodic, and continuous, with the periodic further divided into 5 subsets. It will be appreciated from this list how nominally complex the problem of furnace analysis is. Nevertheless, we can still represent any furnace as a box or enclosure formed by a thermodynamic surface and across which surface there are energy flows in and out. The First Law of thermodynamics then enables us to set up an energy balance between the flows, more particularly if the system is in steady state and there is no net accumulation or loss of energy inside the enclosure. This is the basis for the analysis.

### *Heat Recovery and Classification*

Furnace analysis can be applied to a single furnace, or to a furnace with heat recovery equipment, or to a set of furnaces with or without heat recovery equipment. Furnace analysis develops equations to predict behavior of the single furnace unit, without heat recovery equipment. It does not follow a priori that the same equations will apply to the furnace with heat recovery equipment, or to a compound set of furnaces. This has to be established independently. To do this, furnaces are classified according to their methods of heat recovery. The classification used here follows:

Class 1 No heat recovery.
Class 2 Heat recovery on the gas side, for example a boiler.
Class 3 Heat recovery on the materials side, for example billet heating.
Class 4 Heat recovery on both the gas and materials side, for example tunnel kilns.

In the unit furnace (the class 1 design with no heat recovery) it is assumed that the material being processed is essentially at the same temperature. This is not also a requirement for the gases. For such a system the maximum efficiency according to equation 2 is that obtained when the gases leave the furnace at the (uniform) processing temperature and there is no wall loss. Normally speaking the gases do leave the furnace at temperatures above the processing temperature, and this can be small to substantial, meaning anything from 100° to 1,000° or more. In addition, there can be anything from a few percent wall loss, as in a boiler, up to 30 percent or more

## Table 2. A classification of furnaces

A. Classification by type
1. Group I : Batch
   Group II : Periodic
   Group III : Continuous
2. a. Direct fired
   b. Indirect fired (muffle)

B. Classification by heat recovery
Class 1 : No heat recovery
Class 2 : Heat recovery on gas side (e.g., boiler)
Class 3 : Heat recovery on materials side (e.g., billet furnace)
Class 4 : Heat recovery on both gas and materials side (e.g., tunnel kiln)

C. Type amplification
1. Batch (in and out)
   a. Pot and crucible furnaces, e.g., melting : metals, some glasses (day tanks), salt bath heat treatment, antimony ore preparation, etc.
   b. Ceramic kilns (i) for drying (stoves), and (ii) for firing (e.g., vertical downdraft)
   c. Heat treatment : metallurgical and others (e.g., glass) reheat, soak, stress relieve, forge, etc. (many are car bottom without or with recycle)
2. Periodic (intermittent or semicontinuous)

| | | |
|---|---|---|
| a. | Vertical shaft | 1. Blast furnace for smelting : iron, tin, antimony, lead, phosphorous<br>2. Cupola : for melting : cast iron production; copper<br>3. Lime burning<br>4. Mercury ore |
| b. | Horizontal hearth | 1. Open hearth : steel refining (also AJAX, Bryndal)<br>2. Reverberatory : copper "matte" production; copper refining; Ni, tin, bismuth smelting |
| c. | Stills | 1. Horizontal coke oven retort : coke oven and town gas<br>2. Metals refining : mercury, zinc, cadmium/zinc/lead |
| d. | Converters | 1. Bottom blown : iron (Bessemer), copper<br>2. Top blown : LD, LDac (BOF), KALDO |
| e. | Others | 1. Brick kiln<br>2. Fluid bed dryers<br>3. Gasifiers (water gas, oil gas) ([illegible]) |

3. Continuous
   1. Boilers : shell and water tube
   2. Glass tanks : cross fired and end fired
   3. Tar stills (separative distillation for petroleum fractions)
   4. Coal distillation (destructive) : continuous vertical coke oven retorts
   5. Total gasifiers : Lurgi, Koppers-Totzek, Wellman, Morgan, etc.; Hygas, Bigas, Synthane, Hydrane, etc.
   6. Car bottom (or single hearth); also rotary hearth; also conveyor
      a. metallurgical : stress relieving, heat treatment, etc.
      b. glass and ceramic : stress relieve; tunnel dryers & kilns
   7. Billet furnaces : pusher, conveyor, roller
   8. Multiple hearth : sulfide ore roasting (copper, nickel, zinc, tin, mercury, lead)
   9. Rotary kilns : a. dryers (sand, etc.), b. roasting (lime, cement, clay)
   10. Flash roaster
   11. Sinter (Dwight-Lloyd) (iron, lead, zinc)
   12. Controlled atmosphere, gas producers
   13. Fluid beds : boiler firing and other purposes

as in a glass tank. In a furnace such as a boiler, the walls (which represent the load) are at a substantially uniform temperature, and this presents a Class 1 component of the total system. The boiler with the economizer and air heaters, etc., comprise the complete Class 2 system. In such a system the gases leaving the unit center will exceed the processing temperature (in a boiler the processing temperature can be as low as 250° to 300° F), but after passage through the heat recovery equipment the exhaust or stack gases can be lower or substantially lower than the processing temperature. In this way the efficiency of the overall system is increased.

Where the material being processed only has to be heated to accelerate certain reactions, such as the brick-forming reactions, there is no need for the material to be delivered hot and it can therefore be used as a source of preheat for the air. This is the case, for example, in many tunnel kilns, where incoming green brick is preheated by counter flowing, exhausting hot gas. When the brick reaches the firing section it is heated to the required temperature after which it travels to the other end of the tunnel kiln in counterflow to incoming air, thus preheating the air and being cooled. This is intrinsically a very efficient system since, in the limit, the fuel required is only that required to balance the heat losses through the walls. All other heat requirements are cycled internally inside the system. It is also a system that would not be a particularly good candidate for a heat transformation because of the high temperature the brick must be raised to, to get the brick forming reactions to occur in a reasonable period of time.

*Operational Performance of Furnaces*

For the purposes of analyzing efficiency, the behavior of interest is the variation of firing rate, or heat supply rate with output, representing the heat removal rate as useful heat. In spite of the diversity of systems, all furnaces are found to have effectively the same performance characteristics so far as the variation of thermal input and thermal output are concerned. The variation of heat supply rate with heat removal rate is known as the firing curve, and it is illustrated in figure 4. Qualitatively this curve has a characteristic shape for all furnaces so far examined, and also, incidentally, for power producing devices (ref. 8).

The characteristics of the firing curve to take note of are as follows. First, when the furnace is at idle but ready to produce, or the power machine is also at idle ready to drive, output is zero, but an idle heat input or zero load firing rate is always required. This serves to balance the wall losses or the internal frictional behavior of the device. When the furnace is producing, or the machine is driving, energy is now being removed from the system, and the firing rate must increase correspondingly. The increase, however, is nonlinear with output because, as the energy is withdrawn, there is an associated loss of heat to exhaust. A linear increase of firing rate with output would mean that each new increment of fuel shared its heat with the output and the exhaust in a constant proportion. This does not, in fact, happen, because as firing rate increases the residence time of the gases in the combustion chamber or furnace falls. With less time to exchange heat with the stock, or to produce power, an increasing fraction of the heat released goes into the exhaust. As the exhaust temperature rises (and a smaller fraction of the heat goes into useful output), the firing rate must again be increased to offset the diminishing transfer to useful output. The consequence is the concave upwards shape of the firing curve, with a final limit as the firing rate theoretically goes to infinity at a finite output.

Clearly this infinite limit is a theoretical condition only, and not realizable in practice, because the fuel supply system would obviously choke long before that point is reached and the combustion efficiency would also start to fall off drastically. It is still a limiting condition with the theoretical significance in that, at infinite firing rate, the transit time through the combustion chamber is zero, and if reaction of the fuel is infinitely fast, the gases in the chamber will be at the adiabatic flame temperature. At that temperature the maximum output of heat or work is then obtained. This provides a basis for estimating the maximum theoretical output of a furnace or engine.

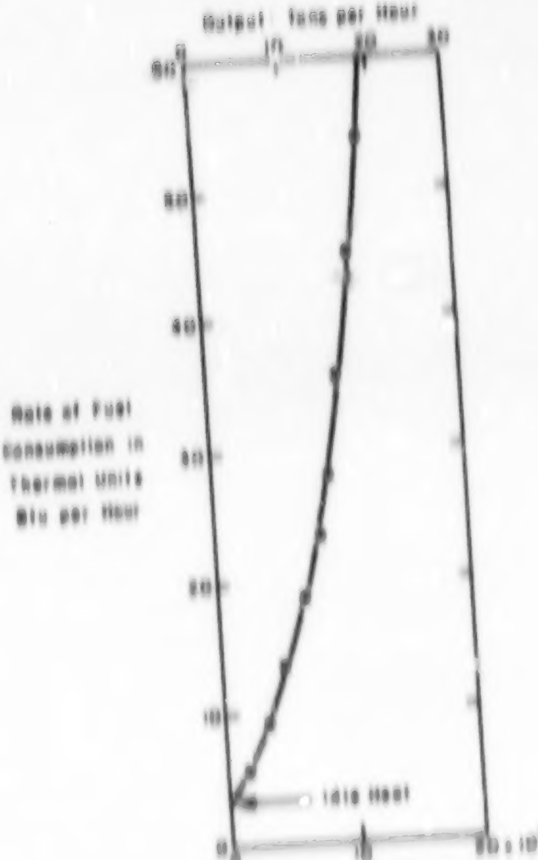

Figure 4. Variation of fuel consumption rate with output for a continuous billet heating furnace. In this figure the heat supply rate and heat output rate have been plotted to the same scale to emphasize the (normally) great disparity between the two.

Even more striking than the common qualitative behavior of the firing curve is the establishment of a common equation describing that curve. Writing the thermal input from the fuel as $H_f$, Btu per hour, and the equivalent useful thermal output as $H_u$, Btu per hour, the common equation has the following form:

$$H_f = (H_f^0 + H_u/\eta^0)(1 - H_u/H_u^0)^{-1} \qquad (6)$$

where $H_f^0$ is the idle heat requirement, $H_0^m$ is the maximum output, and $\alpha^0$ is the intrinsic efficiency. Using the definition of equation 1 we obtain from equation 5 the expression for the thermal efficiency:

$$\eta = \frac{H_0}{H_f} = \frac{\alpha^0[1-(H_0/H_0^m)](H_0/H_0^m)}{\{\alpha^0(H_f^0/H_0^m)+[1-\alpha^0(H_f^0/H_0^m)](H_0/H_0^m)\}} \qquad (6)$$

This equation describes a curve having an asymmetric inverted U-shape as illustrated in figure 5. It will be seen from this that efficiency reaches a maximum at a particular or optimum output. There is a further intrinsic efficiency that can be defined, where we will describe the efficiency of equations 1 and 6 as the operational efficiency, and we will define the intrinsic efficiency as being the limit of Thring's (ref. 4) Heat Utilization Factor, α. Thring argued that the idle heat was used only to balance wall losses and the associated stack gas loss, and that the wall losses were relatively insensitive to output. Therefore, the energy available for transfer to the load was only $(H_f - H_f^0)$. He therefore defined the Heat Utilization Factor as a factor that distributed the energy actually available between the useful output and the stack losses. This factor (α) is formally defined as:

$$\alpha = H_0/(H_f - H_f^0) = \alpha^0(1 - H_0/H_0^m) \qquad (7)$$

Equation 7 is the equation of a straight line of negative slope, with a maximum value (which is the intrinsic

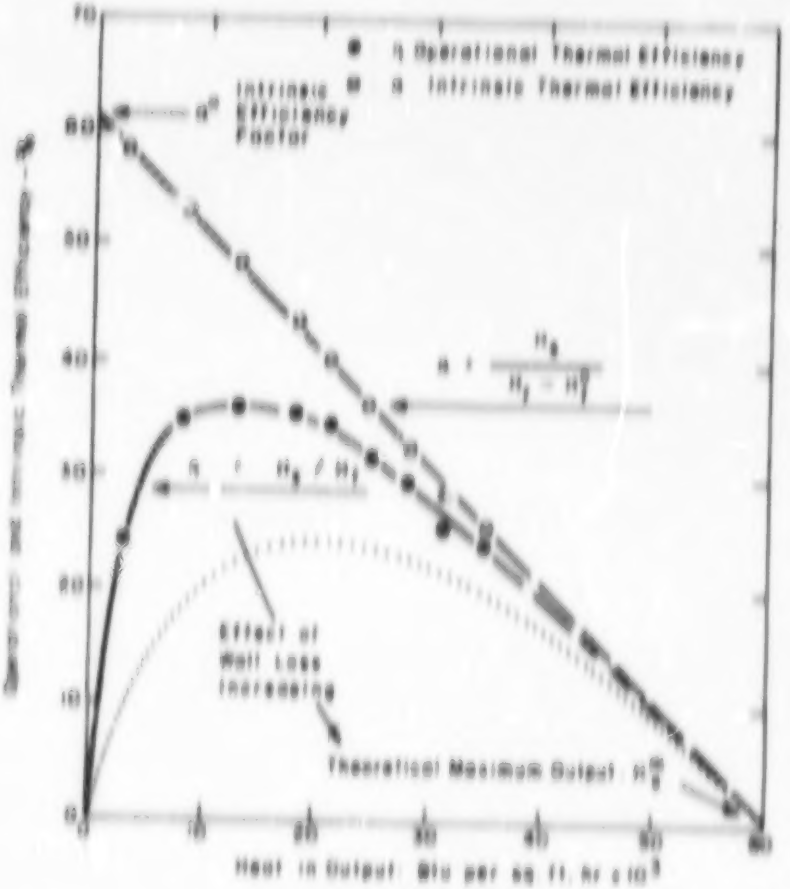

Figure 5. Variation of operational and intrinsic thermal efficiency with output for the billet heating furnace (see figure 4); also illustrating the effect of increasing wall loss.

efficiency) at zero output, and declining to zero at maximum output. This is also illustrated in figure 5, where it is seen that the operational efficiency curve is tangent to the Heat Utilization Factor curve at the maximum output. Figure 5 also illustrates the method of obtaining the limiting extremities, $\eta^0$, and $H_p^m$, by extrapolation of experimental data each way. This has been done for numerous data sources obtained from the literature, and the results have been tabulated in the previously referenced articles (ref. 8). We may note that construction of the Heat Utilization Factor line or curve is possible if we have data for a firing curve, as in figure 4, with the ability to extrapolate with some reliability to zero output to obtain the idle heat. We also note that the use of experimental data in this way will determine a limiting value of $\eta$, namely $\eta^0$, that is the limiting value of the intrinsic efficiency of the furnace as operated. It is not necessary for the furnace to have the gases leaving at the processing temperature for the equations to be valid. If the furnace is redesigned or so operated that the exhaust gas temperature is further reduced, then $\eta^0$ will correspondingly rise, up to a maximum intrinsic efficiency that can then be calculated from equation 2.

It is also potentially possible to estimate the maximum output. If the system is a processing furnace, then the maximum output is determined essentially by the heat received from the flame at the adiabatic temperature. On a unit area basis, the maximum output density can be given approximately by

$$H_p^m = \epsilon\sigma(T_{ad}^4 - T_p^4) \qquad (8)$$

where $\epsilon$ is the effective emissivity for exchange between the flame gases, furnace fabric, and load; $\sigma$ is the radiation constant; and the other factors are as defined.

### 4.4 Factors Controlling Efficiency

From the analysis as outlined above, and incorporating additional information described more fully elsewhere (ref. 8), it has now been possible to identify seven particular factors as having the greatest influence on either operational or intrinsic efficiency. In approximate order of significance these are:

1. Output, as figure 5 shows, is the most important single factor controlling efficiency; it is also the one most commonly overlooked. Over the full range of output theoretically possible, efficiency goes from zero, to a maximum, and back to zero again. Ideally, furnaces should be optimized in design so that their expected output range would approximately coincide with the peak efficiency. This, of course, is generally true of large utility boilers, but it is doubtful that it is ever attempted with other process furnaces.

2. Excess Air is the second most significant factor, and figure 3 illustrates its significant influence. The reason is the increased stack loss when extra air is unnecessarily heated and the heat contained therein is then thrown away. Excess air is controlled in two ways. (a) It is often supplied unnecessarily by poor Fuel/Air ratio controls, or a lack of them altogether. Control therefore requires rationing controls and accurate setting of the controls. (b) The other source of excess air is by inleakage. This can be controlled by properly set and positioned draft gages with automatic damper control, backed up by maintaining a tight furnace shell or skin wherever possible. Excess air is often simultaneously [illegible] the most controllable and yet the least controll[illegible] fuel (and dollar) wasting factors of furnace o[illegible]

3. The Processing Temperature or materials outlet temperature has marked influence on efficiency because of the way this determines the flue gas temperature. The average furnace temperature, according to Hottel, is roughly 200 to 300 degrees higher than the flue gas or gas exit temperature. This must be sufficiently above the processing temperature that the necessary heat is transferred in the time available so that the flue gas temperature will always be just above or substantially exceed the processing temperature. As the flue gas temperature rises, the so-called Available Heat falls, as illustrated by figure 3. Figure 3 is derived from a graph given in the North American Combustion Handbook (1967 edition, p. 50) and it applies approximately to all hydrocarbon fuels. If the wall loss is small, the percentage Available Heat is a fair approximation to the operational efficiency. From figure 3 we can then see immediately that efficiency must drop drastically as both excess air and exhaust gas temperature increases. (It should also be noted, incidentally, that when the wall loss is unimportant, the Available Heat also approximates to the Heat Utilization Factor.) This inevitable reduction of efficiency as the processing temperature increases is an intrinsic consequence of the processing specifications, and nothing can be done about it so far as design or operation of the furnace proper is concerned. Improvements of efficiency, however, can be easily affected by addition of heat recovery equipment.

4. The Flame/Load Temperature Difference is a closely related factor to the furnace temperature effects discussed above, but it deserves separate consideration because of the possibility of altering the furnace temperature by preheat (either by a separate preheater or by heat recovery). Normally speaking, most heat transfer has been found to be by radiation from the flame and furnace fabric to the load. As the temperature difference between the flame (with the furnace fabric) and the load is reduced, the efficiency drops. The efficiency of the

furnace by itself can be increased again by preheat because of the rise in flame temperature and the increase in the temperature difference. This results in a higher gas exit temperature, but figure 3 only continues to apply with corrections to take the preheat into account. If the preheat is by a separate preheater, there is a further loss in efficiency represented by the increased fuel consumption due to the air preheater, but there is the offsetting increase in efficiency of the processing furnace due to the higher internal temperatures. On balance, the efficiency of the combination can be increased. If the preheat is provided by a heat exchanger to recover the heat in the exhaust gas, the efficiency of the combination can be increased very considerably. It is also noted that the improved efficiency by increased $\Delta T$ is a kinetic requirement that is directly opposed to thermodynamic requirements for efficiency.

5. Load Emissivity is also a factor that can have very considerable influence on the efficiency. The efficiency will drop drastically as the load emissivity is reduced. In the limit of zero load emissivity (or more accurately load absorptivity) the efficiency would be zero if there was no convective heat transfer. It follows, therefore, that the traditional conclusion that radiation is the prime heat transfer factor is valid only for loads of fairly high absorptivity. This is generally the case, particularly where the furnace is for high temperature processing since absorptivities generally rise significantly with temperature. Exceptions are certain types of close-packed loads (in brick kilns) where very high velocity burners (up to 200 mph jets) have been found to increase efficiency and throughput very considerably. At lower processing temperatures, the greater temperature difference can make up for reduced absorptivity. Nevertheless, comparisons of different furnaces should take the absorptivity of the load into account as it is by no means an unimportant factor in determining efficiency. Load absorptivity is, of course, something that is most usually uncontrollable. Nevertheless, opportunities for affecting it should not be disregarded. Variable absorptivity is most likely to occur in the glass tank as the result of highly reflecting batch being allowed to spread out over the surface of the melt. Some of the marked changes in fuel requirements of operating glass tanks could be due to this effect. In other systems, more consideration might be given to packing or spacing of the materials being heated, when this is possible, so that the overall absorptivity of the assemblies is increased.

6. Wall Loss is also a very important factor affecting the operational efficiency, but not the intrinsic efficiency, at low outputs. The graphs are not reproduced, but the effect of changing the wall loss is to change $H_f'$ in equation (9), and this is found to affect significantly only the fuel requirements at the lower output conditions. On the efficiency graph of figure 5, the curve, and the position of the peak, is significantly influenced by wall loss between zero load and the optimum load. Beyond that, changes in wall loss have only second order or less effect. Nevertheless, the results do indicate the desirability of adding insulation in most instances, so long as it is not likely to cause problems from overheating and melting or collapse of the inner wall sections.

7. Flame Emissivity has least effect of all the factors so far discussed. This is an interesting conclusion in view of the attention given to flame emissivity in the past. The reason seems to be that there is a close trade-off between the increase in heat transferred from the flame when the flame emissivity is increased, and the reduced heat transferred from the walls due to the greater fraction being intercepted by the flame. An additional compensating factor is the generally lower flame temperature of the more luminous flames, partly because of the greater thermal load due to the higher emissivity, and partly it would seem, due to the longer burning time of those fuels that are likely to generate more luminous flames. At all events, emissivity would appear to have negligible effect on efficiency to a first approximation; any influence would seem to be second order. A further consequence is that furnaces are apparently relatively insensitive to change of fuels from the overall thermal efficiency point of view.

Of the seven items listed above, all affect the operational efficiency, but only five affect the intrinsic efficiency. In determining the intrinsic efficiency, the thermal input rate data should first be corrected for the excess air and then the holding heat, $H_f'$, should be subtracted out. The Heat Utilization Factor, $\eta$, can then be calculated, and by plots such as figure 5, the initial value, $\eta^0$, can be determined. The values of $\eta^0$ can be used as numerical estimates of the intrinsic efficiency for comparisons of different furnace designs and operations. The results of such determinations show that the intrinsic efficiency as defined here is evidently quite insensitive to the design details: dimensions, burner placement, fuel type, etc. These factors influence rather the local heat flux distribution inside the furnace while the gross or overall behavior remains relatively independent of such factors. It should therefore be remembered that the conclusions of this article relate to overall performance; their application to local heat flux distribution problems should be handled with great care. At the same time, however, the relative independence of gross behavior from the factors mentioned would seem to imply somewhat simpler external behavior, with self-compensatory mechanisms in operation, than is usually considered to be the case.

In summary, considering the seven factors significantly affecting the thermal efficiency, we find: processing temperatures are preset, flame emissivity is relatively unimportant, load emissivity is difficult or impossible to control, and flame temperature is only controllable by oxygen enrichment or by preheat. Wall loss is nominally controllable by added insulation, but even this has economic limits where it can be applied, and in very-high-temperature furnaces, it can cause such overheating that it does more harm than good. Indeed, in one particular case (of a carbon graphitising furnace) it was proposed that *increasing* the wall loss by water cooling might permit higher outputs at a higher thermal efficiency in spite of the increased wall loss. Consequently, the scope for improved efficiency lies principally with: (a) better matching of the load to the furnace to insure that operation is as close to the maximum efficiency point, on *average*, as possible; (b) control of excess air by proper fuel proportioning and damper control; and (c) by heat recovery.

### *4.6 Other Factors*

The influence of other varied factors has also been examined, either briefly, or in some depth. Summaries of the results obtained follow.

1. The effect of heat recovery on the gas side was examined in one of the previous publications (ref. 8), but it is now known that the conclusion then reached was incorrect. The original analysis was based on the widely used assumption that the fraction of heat recovered from the stack gas as air preheat can be balanced, on a Btu basis, by a reduced firing rate. Closer examination of the more complex firing equation thus obtained showed that it leads to incompatible physical behavior in the furnace. The assumption is therefore wrong and a better assumption was looked for. The source of the error in the initial assumption turned out to be that exact replacement of potential heat in the fuel by sensible preheat means not only a reduction in firing rate but also an increase in the residence time of the gases, if the fuel/air ratio is maintained at its correct value. Consequently, there is more time for the gases to exchange heat and it is possible to reduce the firing rate still further. It also follows that without this further reduction the gases leaving the furnace after the air preheat and the initial fuel reduction would be higher than with the full firing rate without preheat. A better assumption is that the gas exit temperature should be the same whether the air is preheated or not. With this assumption it is found that as indicated, there is more fuel saving than a direct tradeoff on a Btu basis. Moreover, it is found that the firing equation (eq. 5) remains unchanged in form, with only modified values of the maximum output, the intrinsic efficiency, and the effective idle requirement. The effect, as one might intuitively expect, is to increase the intrinsic efficiency and the maximum output.

2. As mentioned previously, periodic furnaces running over a long campaign, with output averaged over the day or the week, can be treated essentially as continuous furnaces so far as the furnace analysis equations are concerned. A practical problem of applying the analysis does occur, however, when such furnaces are operated at an approximately constant output point. This means that for all practical purposes there is only one effective point on the firing curve, and extrapolation to the idle heat becomes impossible. Nevertheless, if such furnaces can be operated without output for experimental purposes, the measurement of the gas exit temperature during such operation will provide the basis for calculating the value of the intrinsic efficiency. Assumptions about the joint emissivity of heat exchange between the flame and stock at the theoretical maximum can also be used to estimate the maximum output, and it is then possible to construct the curves for the efficiency and heat utilization factor to check the relation between the actual measured efficiency at the prescribed output. An example is provided in figure 6 for a metal melting furnace in which a number of different assumptions were made to construct several different efficiency and heat utilization factor curves. It will be seen in this instance that the output was close to the optimum, but with an unexpectedly wide scatter in the range of efficiency from 20 percent to nearly 40 percent. Further analysis of this particular situation established that this variation in efficiency was most probably due to the different forms in which the metal scrap was introduced into the furnace, some being ingots, some being fine baled wire and sheet, and some being plain sheet. This analysis indicated, therefore, that to improve efficiency one significant point could be the method of baling the scrap and introducing it into the furnace.

3. Little has been done yet on extending the analysis to batch furnaces. Essentially, a periodic furnace is a batch furnace with fresh material inserted as soon as the previous sample has been removed. This means that there will be a minimum insertion rate above which the system behaves effectively as a continuous furnace, but below which the heated material is up to temperature and just remaining there at a nominally idle condition. For such a furnace it can only be said that the efficiency will then start to drop off quite drastically, depending quite strictly on the number of units being processed in unit time. If the number of units being processed is very small in relation to the minimum required to approximate continuous operation, it implies

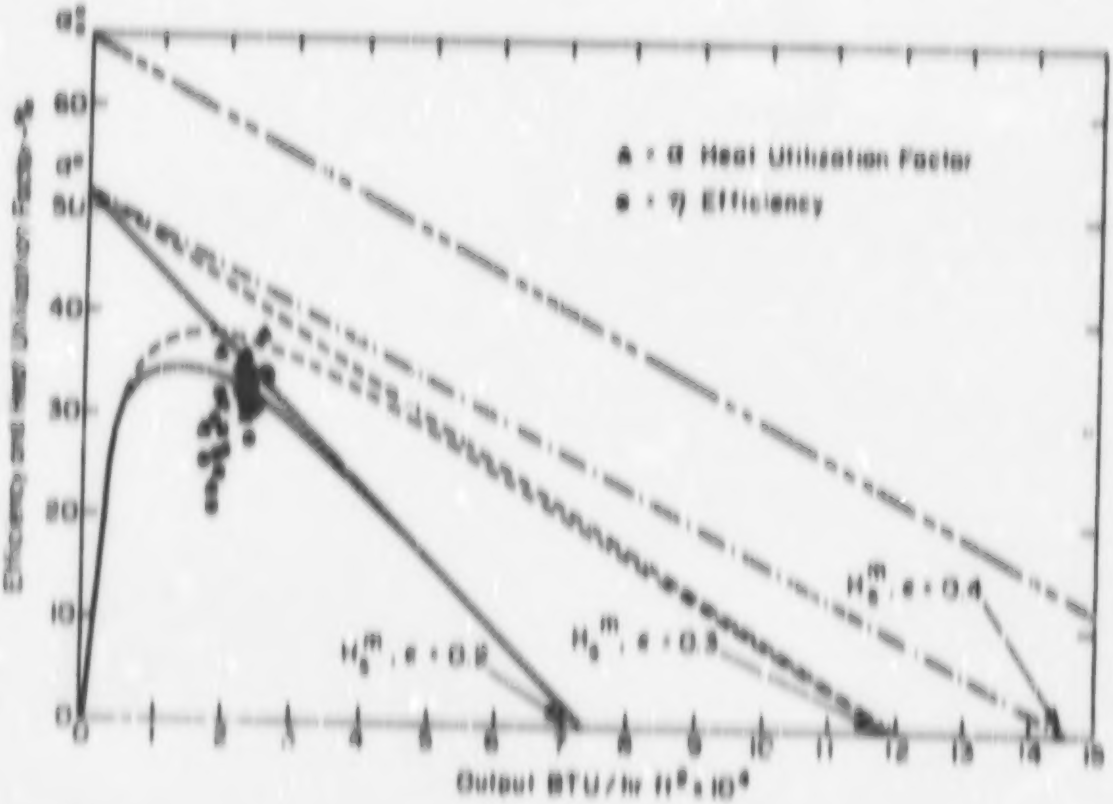

Figure 6. Variation of operational efficiency and heat utilization factor (intrinsic efficiency) with output for an aluminum reverbatory melting furnace (with curves drawn for different flame and load emissivity assumptions; see text).

that the furnace is significantly oversized for the job, and the cure (finances permitting) would be to replace it by a furnace better matched for the duty.

The elements of the analysis have, however, been applied with some success to another type of batch furnace, a vertical downdraft kiln. This was fired steadily on a preset program to give a rising temperature over a period of about 2 weeks. Treating the brick inside the kiln with its rising temperature as equivalent to a steady removal of heat from the firing gases, it was found that the equations described above could be somewhat modified to fit this case. This is an area, however, in which more research is required.

4. Furnace analysis has been applied successfully to the electric furnace. There is of course no stack gas loss, but there is still an idle condition. The variation of stack gas loss, however, is replaced by variable wall loss, which becomes proportionately much more important in such furnaces. It was possible to establish from the analysis that although the operational efficiency of the system lay between 10 and 15 percent, nevertheless, the intrinsic efficiency was very good, being about 60 percent. The system to which the analysis was applied was a Sanders graphitizing oven. This is a furnace with a design such that there is recuperative preheat between carbon blocks entering and leaving the furnace. The high intrinsic efficiency is due to this recuperative element of design.

5. It is also remarkable that the influence of fuel type, i.e. coal, oil, or gas, is relatively unimportant in affecting the efficiency of furnaces. In the first place, the effect of flame emissivity has already been discussed above, with the finding that there is a significant trade-off between increased heat from the flame as flame emissivity increases and decreased heat from the roof and walls as the flame becomes blacker due to its interception. A second factor contributing to the insensitivity of fuel type is the remarkable uniformity of adiabatic

flame temperatures of fossil fuels burning in air. This derives from the purely statistical result that the amount of heat in 1 cubic foot of a stoichiometric fuel and air mixture is approximately 100 Btu's for virtually all the fuels. This rule tends to drop off only in the producer gas and blast furnace gas region. What this approximation implies is that 100 Btu's are being released into 1 cubic foot of mixture. Since in most mixtures the air outweighs the fuel by a factor of 10 to 1 or more, a reasonable approximation is that in the majority of cases, 100 Btu's are being released into 1 cubic foot of cold air. The approximate calculation shows that the gas temperature reached in such circumstances is approximately 3,600° F. A more accurate calculation that takes into account the increasingly significant weight of fuel as the heat of combustion of the fuel drops is illustrated in figure 7 for fuel data obtained by Rosin and Fredlander (ref. 9). As can be seen, the range is reasonably approximated by the dotted line which is given by the following equation:

$$T_{ad} = T_0 + 3750/(1+750/h_f) \qquad (9)$$

where $h_f$ is the heat of combustion of the fuel. The form of the equation can be obtained from a more accurate expression of the air requirements for burning fossil fuels, as follows:

$$h_f/G_s = A/(1+B/s \cdot h_f) \qquad (10)$$

where A and B are empirical constants whose values are given in table 3, $G_s$ is the stoichiometric ratio of air to fuel by weight; and s is the specific gravity.

## EVALUATION

The purpose of furnace analysis is to develop a plan for action that will lead to energy savings. The evaluation procedure that will lead to any savings, however, is complex. The fundamental basis is clear enough: it is a comparison of actual use against targets for use. This is

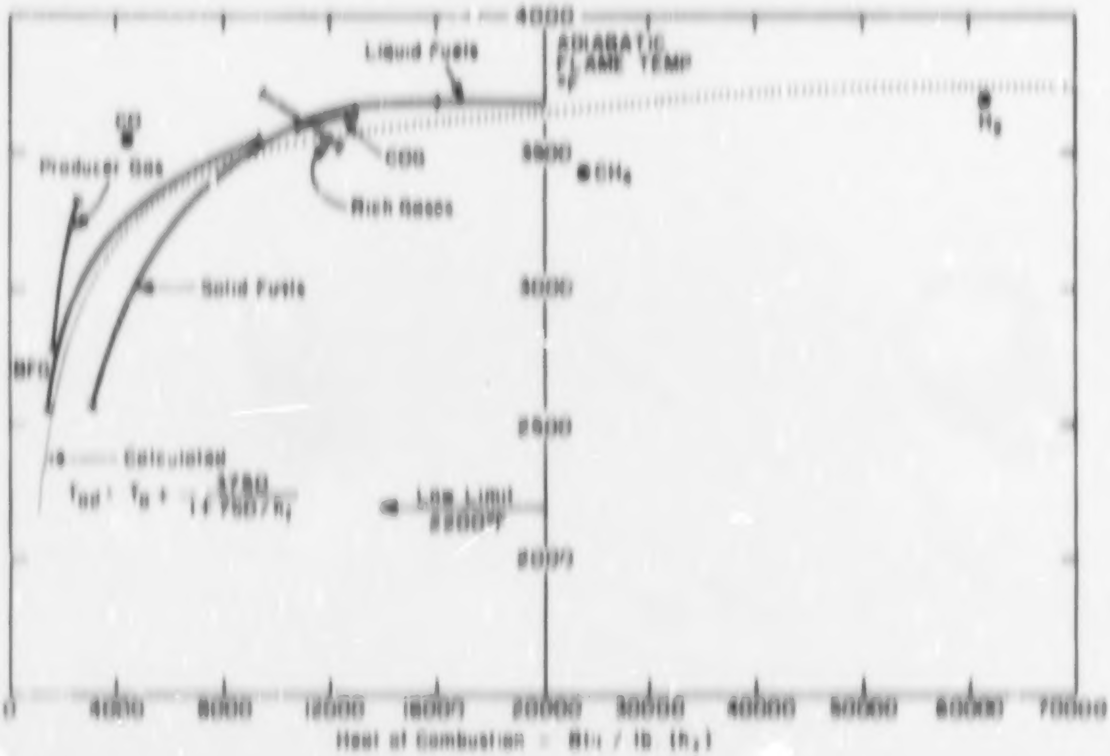

Figure 7. Variation of adiabatic flame temperature with heat of combustion. (Note: change of scale at 20,000 Btu/lb.)

Table 3. Relation between heat of combustion ($h_f$) and stoichiometric air requirements ($C_s$) and common fuels adapted from Rosin and Friedlander (ref. 9)

$(h_f/C_s = A/(1 + B/s.h_f))$

| Fuel | Heat of combustion $h_f$ (Btu/lb) | A | B | Specific gravity s | |
|---|---|---|---|---|---|
| Solid fuels | | | | | |
| | 10,000 | 1,375 | 800 | (1) | |
| | 10,000 | 1,375 | 1,000 | (1) | |
| Liquid fuels | | | | | |
| | 18,000 | 1,537 | 4,233 | (1) | |
| Gaseous fuels | | | | | Btu/ft³ |
| Blast furnace gas | 1,000-1,500 | 1,740 | 0 | 1.0 | 90-115 |
| Producer gas | 1,250-4,000 | 1,506 | 0 | 0.8 | 90-300 |
| Blast furnace gas + coke oven gas | 1,500-8,000 | 1,302 | 210 | 0.75-0.25 | 90-450 |
| Medium Btu gases | 8,000-19,000 | 1,275 | 320 | 0.45-0.95 | 300-500 |
| CO | 4,360 | 1,780 | 0 | 0.97 | 341 |
| $H_2$ | 61,035 | 1,780 | 0 | 0.07 | 343 |
| $CH_4$ | 23,861 | 1,386 | 0 | 0.55 | 1,007 |

simple enough: the complexities emerge in the details. The first step—the comparison of use with targets—yields estimates of losses. It is then necessary to evaluate the losses, and classify them according to their different possible sources. The nature of source of loss can affect the way in which the actions to save energy are implemented. The initial evaluation must be against targets set for the equipment and plant as it exists. Subsequent to that, there would then be a review of the processes to determine what alternative procedures or processes could be adopted, and set new targets accordingly. We therefore have an initial set of five steps, as follows:

1. Determination of use—this is the energy audit,
2. Setting targets for the existing equipment,
3. Comparison of use with targets to determine sources and magnitudes of losses,
4. Review of overall procedures to determine possible alternative processes and set targets based on alternatives, and
5. Developing and implementing plans for action to save the fuel.

1. The energy audit is a procedure with a well established history of four or five decades at least. Lyle (ref. 7), for example, provides numerous examples both of energy balances or audits on individual items of equipment, and also on complete plants. What is imperative, however, is the use of a systematic procedure in developing the audit. The following is a description of a typical procedure in a relatively simple case. The essence of the procedure is to divide the whole plant up into a number of smaller and smaller subdivisions and sub-subdivisions defined by thermodynamic surfaces. Across these surfaces there will be energy flows in and out—the energy flows between all the different subdivisions must of course balance overall. One objective of the division is to reduce a plant to a set of energy conservation centers, where each center will be the basis for an individual evaluation. In this way, small flows that are small in relation to the total energy use in the whole plant may show up as significant on their local scale. For the simple system we can then construct the following six set sequence as follows:

a. Plant balance: all sources of energy supply into the plant are identified and summed (not forgetting potential chemical energy to be released in processes other than from fuel). All energy flows leaving the plant are identified and summed (remembering that, for example, iron as metal represents an energy flow out as potential chemical energy with respect to its oxide if the material arrives as oxide). The difference between energy in and out is the total losses and errors, to be accounted for in the subsequent enclosure balances. This is a first gross target figure.

b. Conversion units balance: if electricity and/or steam or some other energy stream (such as producer gas) is generated on site in a central conversion unit, an energy balance on such a unit is identified as a "secondary" energy supply. The balance on all such conversion units will of course provide a figure for losses that in this instance can be split into stack gas losses and "wall" losses.

c. Intershop balance: an energy balance between the total gross energy supplied to plant minus that used in the conversion units plus the "secondary" output from the conversion units and minus the sum of the energy supplies to each individual shop is now constructed. The difference will represent intershop transmission losses and errors of measurement. Such a balance is not always possible since the individual shops are not always metered individually for all their input energy flows. Where such individual metering is not employed, clearly it should be considered as a future task. In the absence of such metering, estimates of transmission losses can be worthwhile and may already be available in the files as original design calculations. The results of this sequence of calculations is to generate a value for the *net* energy supply to the process shops. Subtracting the total energy out of the plant as in a above leaves a *net* target figure to be accounted for in the remaining enclosure balances.

d. Shop balance: steps 1 and 3 are now repeated on the individual shops including step 2, if appropriate, and with the inclusion in some instances of a tertiary energy supply such as sensible heat of inputs, etc. This shop balance yields a difference that is the sum of the intrashop losses plus measurement errors that have to be accounted for in the final process units balance. Shop heating requirements are included at this stage.

e. Thermal process units balance: each individual process unit (furnace etc.) is now subjected to the same procedure yielding a balance that should provide data on: energy in product, energy in the stack gas, and energy in wall losses. At this point, discrepancies in the balance are solely errors of measurement, and these are frequently found to be considerable.

f. Final balance: in principle, the data for a total balance in detail for the whole plant are now available. Assuming this to be so, with unaccountable losses reduced to acceptable, if not tolerable levels, the data are now reduced to graphical flow form (Sankey diagrams) in which energy flows are represented by bands of width proportional to the quantity of energy to be represented. At the same time, the numerical balance provides a gross energy input to the plant, a net output in the product, a sum of all identified losses, and a balance of unidentified losses with errors of measurement. As mentioned previously, the identified losses split in two: the losses *during* process; and interprocess losses. The distinction between the two is important since the method of dealing with each category is fundamentally different.

This completes the process of "getting the numbers" that action must be based on, with the data now presented visually in a Sankey (Energy Flow) diagram, first for the whole plant, then for the onsite conversion units, then for the intershop balance, if this is significant, then for the individual shops, and finally for each individual thermal process unit. The diagrams then also provide ready summaries for plant managers, plant engineers, shop managers, and so on.

2. Setting the targets has already described in outline above, and in greater detail in the previous publications (ref. 8). Further comment is redundant at this time except to emphasize that this first target setting should be for the equipment as it exists. Having set targets, the Sankey diagrams for the individual energy conservation centers and then for the total plant should be redrawn with the targets as the basis for the revised Sankey diagrams.

3. With the energy audit and the target settings complete, the basis then exists for their comparison and for the determination of losses on the plant as it exists. The losses can then be identified as due to a number of different causes: we may identify poor operational procedures, inefficiencies of furnace and/or plant design, and losses due to the use of less efficient systems than others available.

a. The poor operational procedures can be technical procedures or even scheduling procedures. Reference to figure 6 shows that efficiency peaks are at an optimum output or throughput. If scheduling of material through the plant causes wide swings in output, this can result in unnecessary reduction in efficiency. First, of course, it is necessary to carry out appropriate experiments and measurements on the furnace to determine where that optimum may be.

The poor operational procedures may include such factors as uncontrolled excess air, as discussed previously, or for maintenance that allows excessive air inleakage, and so forth.

b. Considering inefficiencies of plant design, one can turn up several unexpected factors. For example, one point already discussed above is the matter of designing the furnace with an optimum wall thickness and specified brick, costed on the basis of costs prevailing at the time the furnace was designed. This can mean that design procedures developed 20, 30, or 40 years ago may lead to unnecessarily thin quantities of insulation, and unnecessarily low qualities of brick, in the light of today's fuel prices. If the furnaces were built at the time the original calculations were made, then they represent an optimum for that original period, and it may not be possible to do too much about it now in terms of added insulation, as also discussed above. What one should bear in mind, however, is the use, particularly, of computer programs containing value judgments of relative significance of cost that are now out of date but are still being used. Again, for a furnace already built, it may be too late to do much about it; but, clearly, it is an obvious move to check on the assumptions in optimizing costs in new construction.

A closely related point is the question of wall thickness and need for insulation on day furnaces. Many years ago, calculations were carried out that showed that, in dense brick, the heat stored in the wall was anything between 10 and 100 times the hourly loss rate through the wall. Therefore, it was argued, one lost more energy heating up the wall to operating temperature, day by day, if one had a thick wall than was lost by conduction and convection through the wall. Therefore there was little point in having thick walls, so long as they were strong enough for structural integrity. Increased hourly loss, integrated through the day, was still likely to be less than the amount that had to be stored in the wall before the furnace was up to temperature. Consequently, a rule of thumb emerged according to which "day furnaces need little insulation." This is in fact unsound on two grounds, yet it appears that many day furnaces were built according to this recipe. The two grounds are: first, that a furnace does not cool down completely overnight, so that it is not in fact necessary to have to bring it back up to temperature from cold everyday — indeed there is a tradeoff: the more heat stored in the walls, the larger the time constant for heat loss, and the closer to operating temperature the furnace may be the following day; second, this prescription ignored the development of light weight, therefore, low-density insulation brick (particularly the hot face insulation brick that can be used with adequate support from a steel frame structure and in many cases without the use of dense brick). It is doubtful that furnaces today are designed on such principles, but since the life of a furnace can be, if necessary, several decades, it is not impossible that day furnaces built according to that prescription are still in use.

A third point is the problem of heat recovery. It looks like a very simple procedure to recover waste heat from the exhaust of a hot furnace. However, it turns out that there are restrictions not commonly appreciated. The chief problem is the use that the heat recovered is to be put to. The simplest use, of course, is probably to raise steam in a waste heat boiler. However in the case of a large plant with a larger number (say 100 or more) of high-temperature furnaces, each with its individual stack releasing into the shop, the amount of heat so lost is very substantial; but to collect it all in 100 or more waste heat boilers is obviously absurd, and to collect it all for diversion to a single waste heat boiler would require an almost impossible, spaghetti-like array of ducts from the furnaces to the waste heat boiler. The more obvious solution is to install an air heater. But this too presents problems. If the temperatures are significantly above about 1,000° F, then the degree of air preheat will still be restricted to about that because of the need to use a parallel flow recuperator since otherwise the allowable metal temperatures may be exceeded. One solution to this problem is to use more expensive, i.e., more refractory metals for the recuperator, but this would make the return on investment look even worse than usual. If ceramic or refractory heat exchangers are used, these are famous for cracking in due course, and leaking, and the introduction of combustion products into the preheated air stream can cause severe problems in some circumstances. There is a further problem of how to use the preheated air. Particularly where so many furnaces are fired by gas inspirator burners, drawing atmospheric air by virtue of the jet action of the inspirator, the provision of preheated air can mean removing all those burners and replacing them entirely. Again this means the use of metals capable of withstanding the necessary preheat, (in addition to the capital investment of the replaced burners). Frequently it turns out that the return on investment does not justify such procedures, at least on the basis of conventional costing. It is easy to say that heat is being wasted. Methods of recovering that heat are also well known. Nevertheless, it turns out that frequently the recovery methods are too expensive to be justified.

4. In the review of possible alternative procedures and processes, this is where attention can be given to such things as rearrangement and redesign of the plant layout, investigation of the potentially possible application of heat transformers, and so forth. This is where the so-called Second Law evaluations of efficiency may be appropriate.

5. The final step in evaluation is to develop and implement an action plan. The all important factor here is establishing probable magnitudes of expected savings and using, jointly, the magnitude of the savings and the expected cost of implementation as a basis for priorities. A set of do's and don'ts without any evaluation of priorities can be worse than useless. It can lead to tying up expensive equipment and manpower on some jobs that provide relatively trivial savings, while the big losses go unremarked and unchecked. A common procedure has been to pay marked attention to savings in electricity, for example, particularly by turning off the lights. However, if turning off the lights saves 10 percent of the electricity used for lighting, which is itself 20 to 40 percent of electric use, the overall national saving is less than 1 percent, hardly justifying the excessive attention given to lighting. There can indeed be alternative reasons for emphasizing saving on electricity: on occasions it can provide a useful savings in cost and it also has the advantage of immediacy and a form of visibility. The psychological effect in a plant of showing that action is being taken can be most important. At the same time, however, this can backfire completely if plant operators are aware of much more significant factors that management are ignoring. The overwhelming advantage of the systematic evaluation procedure, on the other hand, is that it compels attention to the factors of prime import-

area. As Lyle (ref. 2) frequently observes, the systematic data gathering procedure can also lead to an immediate awareness of how energy streams previously considered waste can be immediately and relatively cheaply diverted to use. Consequently, therefore, the systematic data gathering procedure and evaluation tends to run several of the steps together, with changes in procedures, plant layout, and ordering installation of new equipment sometimes taking place almost at the same time. The essentials, however, remain unchallenged: the energy audit is required to determine the actual use of energy, the development of energy use targets is required for comparisons and identification of losses, and to provide the basis for effective action for saving energy.

## CONCLUSIONS

We may draw a number of sequential conclusions from the foregoing review, starting with the question of the approximate overall efficiency of energy use in industry. This as remarked earlier is usually quoted at 70 to 80 percent. First, we can see from table 1 that half the energy used in industry is for raising steam. Efficiencies on this in a well run boiler plant can be 75 to 85 percent. There are, however, many boilers throughout industry that are given far too little maintenance and other attention, and efficiencies of some smaller boilers could easily be as low as 50 percent even if we take 70 to 80 percent as bracketing the average efficiency of steam raising in the first place. Then we have to consider the efficiency of the actual use of the steam. Good estimates for the efficiency of use of the steam are hard to find. We may, however, note that in the last year or two there has been much comment on two sources of waste of steam: first, excessive steam leaks to the point that a steam cloud above major steam using plant was said to be quite a common sight, and second, there has been further comment on the excessive use of steam where steam is used in processing. In addition to that there are the actual thermal losses through the walls of the steam heated reactors and sensible heat losses of effluents in some cases. The overall efficiency of use might be reasonably estimated at 50 percent. This gives us an overall efficiency, including the steam raising itself, of 35 to 40 percent of half the energy use in industry. To that we can then add the efficiency of the heat used in thermal processing as direct heat. This is the furnace sector we have been mainly discussing, and here we may refer first of all to figure 3 as a basis for estimating. In that figure we see that maximum intrinsic thermal efficiencies of the higher temperature reactors are under 50 percent to start with. We then add to figure 3 the increased gas exit temperature above the processing temperature, a higher actual processing temperature than the minimum listed in figure 3, plus excess air that can be anything from 20 to 100 percent, plus wall losses that may run anything from a few percent to 30 percent. The final figure for efficiency for the higher temperature furnaces is then found to be on average somewhere between 10 and 20 percent. This in fact is the range given by Trinks (ref. 10) for steel plant furnaces. The average would be about 15 percent, and Trinks also makes the point that many low-temperature furnaces are even less efficient because the stock cannot take the high-temperature gases which are therefore cooled by very high excess air before admittance to the furnace. The third component of industrial use is electric drive, which is very much more efficient in its initial conversion of electric power to shaft output; however, as this represents such varied uses as driving fans, pumps, and mechanical devices in furnaces such as conveyor belts, and so forth, again the overall use will not be as efficient as all that. The final efficiency of the industrial sector would therefore appear to be somewhere between 25 and 35 percent, and it could indeed be as low as 20 percent.

This would seem to indicate a potential for major improvements in efficiency of energy use. Examination of the sources, however, indicates that the biggest loss is still a matter of high-temperature gases leaving the high-temperature furnaces. Secondly, there is no doubt that there are major losses due to bad operation, particularly the age old problem of too much excess air. It is not fully appreciated by most operators, and even more so by most company administrators just how much money is lost due to excessive excess air. The difficulty of appreciating this derives from the inability to see the air traveling through the furnace, and the failure to meter it by weight. It is not appreciated, for example, that very often the greatest weight of material moving through an industrial furnace is nitrogen from the air. To provide a comparison figure: a 1,000-MW electric power station will use about 400 tons of coal an hour. It will also require about 5,000 tons of air an hour, of which 4,000 tons per hour is nitrogen. A single plant processing 4,000 tons per hours, continuously for about 11 1/2 months in the year, day and night, week by week, would normally be regarded as a major plant. Yet when it comes to use of air, the point is missed entirely. What is very often needed here is a relatively small investment in gas analysis equipment for each furnace, and proper (preferably automatic) draft control. The stack gas losses that a company has to live with, unless it installs expensive heat recovery equipment, are already substantial: there is no need to increase them unnecessarily by failure to control the excess air.

By comparison, the attitude towards steam leaks appears to have undergone a transformation with the last 1 or 2 years. The simple calculations to show the magnitude of losses, and then therefore the potential for dollar and fuel savings, have been carried out. Moreover, the steam is very visible. The consequence recently has been the provision by many companies of maintenance teams dedicated to the one job of tracing and curing steam leaks. At the same time there have been parallel reports of inquiries into the real steam needs of different plant components, particularly in the chemical industry, with the conclusion reached in many cases that steam use was excessive or grossly excessive. Actions to cut down on fuel by cutting down steam demand have been evidently very active.

The actions to be taken, in general, to reduce losses and reduce energy demand therefore tend to fall mainly into three principal categories.

1. Tightening up maintenance and operating procedures, as for example eliminating steam leaks or reducing unnecessary excess air, or providing better maintenance of furnace fabrics to reduce or prevent air infleakage.

2. Consideration is also being given to installation of new add-on equipment, notably heat exchangers. However, to this writer's knowledge, there has not yet been too much activity in that direction. The equipment is expensive, and experience has shown that it generally requires very tight maintenance and operation by more highly skilled, and therefore more highly paid workers. The question of costs is therefore crucial, and more often than not it is still reported that the cost of such installations cannot be justified.

3. The third action can be altering the process. This can either be a rearrangement of the existing equipment, or attention to such new factors as the heat transformers. For example, Powell (ref. 11) describes an improvement in procedures in a transportation equipment plant. An axle forging process required three basic operations, billet to roll-formed blank, blank to preformed forging, and preformed to finished forging. Because of the layout of the system each of these operations started with cold metal stock. By rearranging the location of equipment into a single continuous line, the use of heat was reduced by two-thirds and the labor and handling needed was also greatly reduced.

Investigation of energy transformers, on the other hand, has so far been far less successful, at least with respect to industrial operations. It is also generally recognized that the high temperature operations will not benefit from such devices. Nevertheless, the time can be seen when a variety of new approaches to heating at the lower temperatures utilizing the smaller temperature differences will come about. It should certainly not be thought, as does seem to be implied by some recent writers, that the potential of heat pumps and the like has gone unremarked. Neither has the significance of energy degradation been missed. These points, as indicated previously, have in fact been under fairly active and detailed discussion for a period of 30 to 40 years. The principles have been appreciated; what has been missing up to now has been the necessary equipment.

It is indeed a striking fact that what is needed to improve efficiency of industrial furnaces, and industrial use of energy, are actions that have been known for decades. Technical difficulties are not really a problem. The principal reason for now embarking on much more extensive energy-saving operations is costing, which in turn depends on the price of fuel. What does not seem to be generally appreciated is the relatively small cost of energy as a percentage of the cost of manufacturing. For heavy manufacturing, such as steel, glass, cement, heavy chemicals, and so forth, the cost of energy is between 10 and 25 percent of the manufactured costs. But for the whole of industry, as an average, the cost is about 5 percent, having evidently risen to that from 4 or 4.5 percent in the last 1 or 2 years. Since there is a major use on the high side of that average, there must also be major use on the low side of the average to obtain the average. On the high side of the average, companies have generally known of the importance of saving energy, and within what was always permitted by standard cost benefit analyses, or the return on investment, substantial investment was indeed made in energy saving operations. With the further rise in the cost of energy, more energy saving operations can still be undertaken and show a return. On the low side of the average, however, the cost of energy as a percentage of manufacturing costs was, and still is, so low that companies paid little attention to it in the past, and still pay relatively little attention to it today even with the drastic rise in the cost of fuel. The central issue is always the return on investment, and even with the cost of fuel as high as it is today, the return on investment is still too unattractive to pay much attention to much energy saving beyond immediate solutions such as turning out the lights. This is essentially a microeconomic point of view.

From the macroeconomic point of view, on the other hand, what we then see is that all fuel not saved and not domestically available has to be brought from overseas, thus representing flow of dollars overseas that are not used inside the country for further capital investment. Even if the money does return from overseas as capital investment from outside, the return on that still leaves the country, and again from the macroeconomic point of view this represents a significant loss that would justify very much more intensive efforts towards energy saving. This would seem to indicate a direct contradiction between the microeconomic point of view (or the point of view of the individual company) on the one hand, and the macroeconomic point of view represented by the country as a whole. There now seems to be something of a growing appreciation that this contradiction exists, and it would seem to be indicated that the resolution of the contradiction may possibly lie in the recognition that fuel has a value that exceeds its cost. This excess value over cost exists because, within the country, fuel is in limited and diminishing supply. Clearly, if the value exceeds its cost, and if value is then used in place of cost in return on investment calculations, it must follow that some or many decisions about whether to make the investment or not would turn in favor of the investment.

The question therefore arises: on what basis can value be estimated as a multiple of costs? One simple way of viewing this is to ask the additional question: what does a company stand to lose if it does not have the fuel? This is the question that a number of companies found the answer to by involuntary experiment in the last 2 years when they had no fuel and temporarily had to close down. They generally found that there were at a minimum close-down costs, startup costs, union benefits, maintenance expenses, fixed charges, and so forth. As the very simplest method of obtaining an estimate of the ratio of value to cost, one can simply look at the value of product per dollar of fuel, which is just the reciprocal of the cost of fuel as a fraction of manufacturing costs. If energy costs are only 5 percent, the reciprocal view states that there are $20 worth of product for every dollar of fuel. In the case of, for example, a company manufacturing high-quality glass products, which sell for many thousands of dollars, and the gas used is a very small quantity, the value of product per dollar of fuel can run between $100 and $1,000, or even $10,000, in special cases. This starts to emphasize very clearly the value of that fuel if it is not available. Indeed, the reciprocal factor of dollar worth of product per dollar of fuel is a rough estimate of fuel value, and has been used, for example, by Powell (ref. 11) as an estimator for a multiplier to convert fuel costs into fuel value. It is also interesting to note that this approach emphasizes to the small user just how important it is to him also to take steps to conserve energy, where the large user with fuel as a large percentage of his manufacturing costs knows this already.

This is a problem that might perhaps be called the cost accounting barrier. It also seems to this writer to be the most important problem to overcome if energy saving is to become realistic on a large scale. This writer is able to say at present from his personal contacts that some of the larger companies are engaged in energy savings campaigns in which justification for improvements to be carried out is made on the basis of such things as improving a product mix or updating an old component or plant, rather than the precise objective of saving energy merely to justify the expenditures and surmount or tunnel through the cost accounting barrier. The use of the cost multiplier to convert cost into value, with value used in the return on investment calculations, would seem to be another possibly effective way of achieving the same end. This it would seem would be worth exploring further.

In summary, therefore, we conclude that the efficiency of energy use in industry is probably between 25 and 35 percent, and could be lower. The principal source of inefficiency would appear to be the sensible heat losses from many high-temperature furnaces from which heat is discharged at very substantial temperatures to the atmosphere without any heat recovery. There are also large losses that combustion engineers have complained about for decades in the excessive use of excess air, where the use of relatively simple gas analysis equipment could produce very large savings with a payback in some instances of months, if not weeks. There is also scope for substantial tightening-up of operating procedures, improved maintenance, and so forth. There is also need for closer examination of new plant layout, revisions to the processes, and possible benefits from examination of heat transformers. The biggest barrier of all to improved efficiency of energy use, however, is not technical; it is financial: it can reasonably be called the Cost Accounting Barrier. The cost of energy as a percentage of manufacturing costs is still on the average so low that purchase of necessary energy saving equipment such as heat exchangers, and so forth, is still difficult, if not impossible to justify on current accounting rules. This, perhaps, is the area where, by reassessment of accounting rules and recognition that the value of fuel exceeds its cost, there could in fact be the greatest benefit in improving efficiency of energy use in the shortest possible time.

## APPENDIX I
## SUMMARY OF THERMAL EFFICIENCY AND EFFICIENCY RATIO EQUATIONS

The operational efficiency of any system is only a partial guide for evaluating the system performance. The operational efficiency is certainly the central factor regarding actual fuel consumption, but it also needs to be compared with the best efficiencies that the system is capable of, and also compared with the best efficiencies that some other optimum system is capable of. The maximum efficiencies can be used for normalizing the operational efficiencies, thus generating the efficiency ratios.

*Efficiencies*

Four efficiencies can be defined, with some identical in some instances (see table A1):

1. $\eta$, the operational efficiency, defined by equation 1;
2. $\alpha^0$, the intrinsic efficiency, defined by equation 5;
3. $\eta_{max}$, the maximum possible operational efficiency of the system of concern; and
4. $\eta^0_{max}$, the maximum possible efficiency of the optimum system that will achieve the given task (best task efficiency).

With further definitions below we have:

$$\eta = E_u/E_g \qquad (A1)$$
$$\alpha = E_u/(E_g - E_g^0) \qquad (A2)$$
$$\eta_{max} = E_u/E_{g,m} \qquad (A3)$$
$$\eta^0_{max} = E_u/E_{T,m} \qquad (A4)$$

where, with units of either heat or work:

$E_u$ = useful energy used or delivered by system,
$E_g$ = gross energy actually supplied to system,
$E_g^0$ = "idle" point energy,
$(E_g - E_g^0)$ = net utilizable energy supplied to system,
$E_{g,m}$ = minimum gross energy required by system, and
$E_{T,m}$ = minimum gross energy required by the optimum system that will achieve the given task.

It is noted that the minimum required input energies ($E_{g,m}$ and $E_{T,m}$) will be equal to the available energies (AB) where:

$$B_I = U + p_0V - T_0S \qquad \textit{for batch systems}$$
$$B_{II} = U + pV - T_0S = H - T_0S \qquad \textit{for flow systems}$$
$$= H - T_0S + (V^2/2g) + z \qquad \text{(for general flow systems)}$$

*Efficiency Ratios*

These are defined as:

$$r_s = \eta/\eta_{max} = E_{g,m}/E_g \qquad (A5)$$
$$r_T = \eta/\eta^0_{max} = E_{T,m}/E_g \qquad (A6)$$
$$r_{ST} = \eta_{max}/\eta^0_{max} = E_{T,m}/E_{g,m} \qquad (A7)$$

Equation (A5) compares the system, as operating, with itself at optimum operation. Equation (A6) compares the system as operating with the optimum task system. Equation (A7) compares the optimum of the system in use with the optimum task system.

When $E_g$ is supplied as work, equation (A6) is clearly the "Second Law" efficiency as defined in reference 7. This is also found to be true for energy supplied as heat from a reservoir, and approximately true for energy supplied from fuels. Reference 7 compares the "First" and "Second Law" efficiencies for nine single source and single output systems based on the following:

*Sources:* (1) work; (2) energy from fuel; (3) heat from a reservoir.
*Outputs:* (1) work; (2) heat supplied to a device; (3) heat extracted from a device.

The matrix of each source satisfying each output generates nine systems.

Table A1 compares the same nine systems for three of the four efficiencies (with $\alpha$ appearing only in systems five and six), and for the three efficiency ratios. The efficiency commonly referred to as the "First Law" efficiency is $\eta$; that commonly referred to as the "Second Law" efficiency is $r_T$. However, the rationale for choosing these two as the "First and Second Law" efficiencies out of the six or seven options is not clear.

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Table 4[illegible]. Efficiencies [illegible] and [illegible] and efficiency ratio [illegible] for single-source, single-output systems
(adapted from table 2.2 of ref. 7)
Note: Task efficiency ratio, [illegible], is equal to or approximately equal to "Second Law" efficiency of ref. 7.

| Demand \ Source | [illegible] | Work supplied [illegible] | Energy supply from fuel [illegible] | Heat supply from hot reservoir [illegible] |
|---|---|---|---|---|
| [illegible] | [illegible] | [illegible] = 1 (1) | [illegible] = 1 (2) | [illegible] (3) |
|  | [illegible] | [illegible] = 1 | [illegible] | [illegible] |
|  | [illegible] |  | = 1 [illegible] |  |
| [illegible] | [illegible] | [illegible] = 1 | [illegible] | [illegible] |
|  | [illegible] |  | [illegible] |  |
|  | [illegible] | = 1 | [illegible] | = 1 |
| [illegible] | [illegible] | [illegible] (4) | [illegible] = 1 (5) | [illegible] (6) |
|  | [illegible] | [illegible] | [illegible] | [illegible] |
|  | [illegible] |  | [illegible] | [illegible] |
| [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| [illegible] | [illegible] |  | [illegible] | [illegible] |
| [illegible] | [illegible] | = 1 | [illegible] | [illegible] |
| [illegible] | [illegible] | [illegible] = 1 (7) | [illegible] = 1 (8) | [illegible] (9) |
|  | [illegible] | [illegible] | [illegible] | [illegible] |
|  | [illegible] |  | [illegible] |  |
| [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| [illegible] | [illegible] |  | [illegible] |  |
| [illegible] | [illegible] | = 1 | [illegible] | = 1 |

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4 November 1975

## Session IV:

# CENTRAL POWER STATIONS

Fred L. Robson, Ph.D.[1]
Session Chairman

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# WASTE HEAT UTILIZATION/REDUCTION

A. G. Christianson and D. J. Cannon[1]

## Abstract

*Projections indicate that waste heat rejection from central power stations in the year 2000 will nearly equal the total U.S. energy consumption in 1970. Although it is a waste product under our current methods of operation, a significant amount of this waste heat could be utilized. Three of the more promising options for waste heat utilization/reduction are (1) byproduct waste heat utilization, (2) byproduct electrical generation by industry, and (3) integrated energy production/use complexes. The implementation of these options could yield sizable short-term, midterm, and long-term environmental, economic, and energy conservation gains; however, because of the long lead times involved for planning, design, and construction of these facilities, work should be initiated on each of the options now.*

*In order to successfully implement these options on a commercial scale, many technical, economic, and institutional problems must be overcome. The degree of success achieved will be dependent on the ability of energy producers, energy users, and government to mutually solve these problems.*

## INTRODUCTION

This presentation is based on the premise that our nation's environmental, energy, and economic considerations are increasingly interdependent. A prime example is the impact that the trends in electrical generation have on the production and management of waste heat.

Electrical energy requirements are projected to be the predominant energy growth factor over the next 30 years. Whereas the total U.S. energy demand doubled in 22 years (between 1950 and 1972) (ref. 1), the historical trend of electrical production over the past 50 years has been a doubling every 10 years (about a 7 percent annual increase). These trends, predicted to continue, indicate the increasing role of electricity relative to other energy forms in meeting our energy demands.

In terms of national energy conversion efficiency, growing demand for electricity, plus the anticipated continuing increases in transportation uses (as much as 3% percent per year) will result in an increase in overall conversion losses from about 50 percent in 1970 to almost 55 percent in 1990 (ref. 2). If such projections hold true, the impact on resource requirements and waste generation are rather startling. A national decrease in energy conversion efficiency from 50 percent to 45 percent results in an 11 percent increase in fuel input requirements on a unit Btu basis, i.e. *not* considering the growth in energy demand. The same efficiency decrease results in a 22 percent increase in waste heat production, again on a unit Btu basis.

Looking more closely at electric power generation, in 1973, it accounted for a resource requirement of 19.8 quads ($19.8 \times 10^{15}$ Btu's) out of a total national energy input demand of 75.5 quads—i.e., about 26 percent of the total (ref. 4). The waste heat losses in conversion amounted to 13.5 quads, which is about 18 percent of our total national energy requirement. Waste heat is also rejected from nonelectrical sources, but the amount while exceedingly high is not easily quantified.

For a final comparison, it is interesting to consider both growth rate and magnitude of waste heat production. With electrical demand doubling every 10 years, the predicted heat dissipation from central power sources in the year 2000 is about 72 quads (ref. 3). This quantity of waste heat is equal to the *total* U. S. energy demand of 1970.

Rejected heat is considered a waste product in terms of our current methods of operation. At an equivalent of more than one-sixth of the Nation's total annual fuel requirement, it must be considered for utilization or reduction through innovative planning and management by both electric utilities and other industries. A new emphasis must be given to the possibilities for improving conversion efficiencies and waste heat utilization—for the sake of energy, environmental, and economic resources.

In terms of energy impact, ERDA (ref. 5) identifies the potential savings in energy in the year 2000 for these relevant categories as follows:

Industrial Energy Efficiency (Highest Priority, Near-Term Efficiency [Conservation] Technology)—8.0 quads

Waste Heat Utilization (Important, Midterm Technology)—4.0 quads

These objectives are significant in terms of reduced environmental impact because of reduced emission of heat and other pollutants and also because of reduced economic impact of pollution control.

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The Environmental Protection Agency (EPA) has been involved in waste heat reduction and control activities primarily because of its mandates for environmental impact mitigation. However, the economic impact of pollution control technology has become an increasingly prominent consideration, i.e., as the degree of pollution control is increased, the *incremental* benefit/cost ratio becomes more important and requires more exact definition. In other words, we are at the state where "little things mean a lot" with respect to degree of control and related economic feasibility.

There are numerous options available for waste heat utilization/reduction. We have focused on three options which we feel have good potential for future application. These are (1) utilization of byproduct waste heat discharged from conventional industrial and utility plants, (2) generation of byproduct electricity in industrial plants, and (3) development of integrated energy production/use complexes which utilize energy more efficiently. The first option deals with the utilization of waste heat after it has been discharged from a process or facility, while the second and third options involve optimizing the design and management of the process itself to reduce the waste heat discharge.

In order to capitalize on these waste heat utilization/reduction options, we see the need for emphasis in research and development in all three areas. Because of the long lead times and the long lifetime of the systems proposed, it is important that planning be initiated now in all three areas.

## INCENTIVES

In the past, low fuel prices, plentiful supplies of natural gas and oil, and the absence of pollutant control standards gave limited incentives for the utilization of waste heat, generation of byproduct electricity by industry, or construction of multipurpose central generating stations. Under these preenergy crisis conditions, the economic and operational benefits of total energy or waste heat utilization systems were marginal. However, in the past three years the resource, economic, and environmental constraints on the conversion and utilization of energy have changed drastically. The costs of natural gas, oil, and coal have risen significantly. Natural gas is in short supply and many large utility and industrial users are being forced to convert to oil or coal. The availability of oil is uncertain due to reduced production in the United States and the tenuous political situation in the Middle East. Environmental limitations on $SO_x$ has necessitated the installation of scrubbers or the burning of low-sulfur coal. Limits on thermal discharges have necessitated the construction of closed cycle cooling systems or other control measures. Finally, the costs of new construction as well as the cost of capital have risen considerably, making the raising of capital more and more difficult. Predictions point to a continuation of these trends in the future, forcing the cost of energy still higher (ref. 5).

The rates of electrical energy to total energy used in this country have steadily increased and are expected to continue this trend in the future. It is estimated that by the year 2000, 41 percent of our energy needs will be supplied by electricity (ref. 5). Efficiencies for direct fuel conversion range from 70 percent to 85 percent for most industrial facilities. However, the efficiency for single-purpose electric generating stations ranges from 32 percent for light water nuclear plants to 40 percent for HTGR and fossil fuel fired stations, or about half that of industrial energy conversion efficiency. This difference in operating efficiency means that approximately double the amount of fuel must be consumed by these central electric stations (relative to industrial energy use) to deliver a similar amount of energy to the user. For this reason, the pollutant emissions for central stations will be double that of industrial combustion emissions, assuming equivalent pollution control systems. The differences in waste heat generated are equally dramatic. In the future, the problems of fuel availability, pollutant emissions, and waste heat discharges will be compounded by the fact that the electrical energy to total energy use ratios are increasing.

These current and projected constraints on energy utilization have resulted in a significant increase in the incentives for waste heat utilization/reduction concepts. Many of the environmental, economic, and energy conservation incentives for waste heat reduction are interrelated. For example, in reducing waste heat discharges through more efficient production of electricity, fuel will be conserved, pollutant emissions will be reduced, and overall costs will likely be reduced.

### *Byproduct Waste Heat Utilization*

The economic incentives for utilizing heated cooling water in agricultural, commercial, and industrial facilities are currently improving, and are projected to continue improving as the cost of fuel rises. In these applications, heated water (or stack gas) can provide much of the energy formerly supplied by natural gas or oil, thus conserving fuel, reducing the waste heat discharged in the cooling water, and reducing overall costs. There are several aquacultural and agricultural projects of demonstration and commercial scale now underway. The success of these ventures will provide economic and operational information needed to support further development of these applications.

### *Byproduct Electrical Generation by Industry*

Currently, good economic incentives exist for production of electricity by industry, as a byproduct of process steam generation. A recent study (ref. 6) implied that inplant production of electricity by industry would yield a 50 percent savings in fuel, a 60 percent reduction in air emissions, and an 80 percent reduction in waste heat generated (compared to electrical generation in a conventional power plant). Byproduct electrical production will also yield reduced overall costs and an attractive return on investment for the industry. On a national scale, byproduct electrical generation would reduce the total capital needed by utilities for electrical generation.

### *Integrated Energy Production/Use Complexes*

These dual purpose or integrated facilities offer reductions in fuel usage and in pollutant emissions due to their high energy utilization factors. Studies have indicated that a 10-15 percent savings in energy could be achieved in an integrated energy facility. Savings in the cost of delivered electrical power have been estimated at six percent or more (ref. 6). Relatively few of these integrated facilities have been built due to the problems in matching production facilities to users, gathering the necessary capital, and overcoming institutional and other constraints. However, the increasing cost of fuel is improving the incentives for development of integrated facilities.

## OPTIONS FOR WASTE HEAT UTILIZATION/REDUCTION

The discussion of options for waste heat utilization/reduction is focused on three options which we feel show good promise for development on a commercial scale.

The first option, involving use of waste heat after it leaves the conversion facility, has the greatest potential for nearterm energy savings. Currently, most waste heat applications are based on this approach. The waste heat addressed here is the conventional reject heat from an industrial process (e.g., electric power generation) which is an endproduct or byproduct of the process. Typically, it is low-quality heat—usually between 10° F and 40° F above incoming water temperature—such as that available in condenser cooling water from steam electric generating stations.

A number of direct use waste heat applications have been investigated to varying degrees—the more promising methods receiving effort toward demonstrating their full scale feasibility. At preenergy crisis fuel prices, the most economically attractive waste heat applications have been in agriculture and aquaculture. These efforts should be continued and other uses evaluated more thoroughly in light of current energy prices and potential savings.

Agricultural demonstrations of waste heat use have shown promise in areas of irrigation, frost protection, undersoil heating, and greenhouse heating and climate control. Greenhouse applications appear most economical, based on production of high cash-value crops such as flowers or vegetables. Refined systems are currently being demonstrated which should result in commercial involvement in 3 to 4 years.

EPA supported this application of waste heat in the agricultural project it sponsored near Eugene, Oregon, from 1968 to 1973. The project, jointly funded by the Eugene Water and Electric Board, utilized cooling water from a pulp and paper mill to provide spring frost protection, irrigation, crop cooling in the summer, and soil heating. The project was most successful in providing spring frost protection and in increasing crop yields in a greenhouse which was heated by underground pipes.

A second EPA funded demonstration project is now underway at the Sherburne County power plant in Becker, Minnesota. The project will utilize heated water from the condenser cooling loop of the two-unit, 1,400-MWe plant to provide soil heating, and air heating for a half-acre greenhouse. Heating and cooling a half-acre greenhouse in Minnesota for a year normally consumes 25,000 gallons of oil or 3.5 million cubic feet of natural gas. If the half-acre experiment is an economic success, a commercially developed 100-acre greenhouse complex could be in operation by 1985, with savings of 5 million gallons of oil or 700 million cubic feet of gas. The success of this project will be gauged by crop production results and the economics of operation.

The Tennessee Valley Authority (TVA) has recently received funds from EPA to use waste heat to stimulate the growth of algae and amur fish in a project to recycle nutrients from livestock operations. The project will use livestock wastes to grow algae which will subsequently be used to feed amur fish. The amur will then be harvested for livestock food.

TVA is also planning and conducting demonstrational tests of open field soil heating, greenhouse heating, and catfish production using waste heat from condenser cooling water.

Numerous other systems have been proposed or are under development for utilizing low-level waste heat. Currently those projects that involve stimulation of biological growth show the most promise for future development. These include, aquaculture, mariculture, algae production for animal food, and biological waste treatment processes. Additional work, however, is needed to identify species of plants and animals which respond most favorably to waste heat stimulation, and to adequately control the chemical and biological wastes from these activities. Since they have potential for highly efficient protein production, these processes can also be expected to supplement conventional, yet energy intensive, agricultural practices.

The second option, involving the generation of byproduct electricity in industrial plants, has good potential for midterm reduction of waste heat. Nearly 20 percent of the nation's primary fuels are used to produce industrial steam. Only 30 percent of this steam is used to generate electrical power before using the steam for process heating. Most industrial facilities now generate their own process steam with natural gas or oil-fired package boiler and purchase electricity from utilities. Package boilers have been employed rather than field-erected boilers because of their low capital cost, relative simplicity of operation, and the availability of low-cost natural gas and oil. Package boilers usually operate at low steam pressure (below 400 psia) with operating efficiencies of about 75 percent. Field-erected boilers, on the other hand, are relatively high in capital cost, and more complex to operate, but have an operating efficiency of 88 percent and twice the useful life of package boilers.

Approximately 43 percent of the industrial steam load is produced in amounts of 400,000 lb/hr or more at single locations. At facilities this size and larger, it would be advantageous to install field-erected boilers and produce byproduct electricity inplant. For example, coal-fired, a field-erected boiler producing steam at 900 psia and 825° F, and a turbine back pressure of 150 psia would have an effective conversion efficiency of 4,500 to 5,000 Btu/kwh as compared with a rate of 9,000 to 10,000 Btu/kwh for an efficient central power station (ref. 6). The electrical power, therefore, could be generated with half the fuel required by a utility plant, not to mention a large reduction in electrical transmission losses.

The superior efficiency in byproduct electrical generation is due to the fact that the turbine exhaust (steam at 150 psia) can be utilized for process heating, whereas conventional power turbine exhaust heat is "wasted" to the environment in the cooling water or the atmosphere. In addition to the greater efficiency in electrical generation, the utilization of a field-erected boiler rather than a package boiler will result in about a 13 percent increase in boiler efficiency. Add to this the longer equipment life, and the field-erected boiler with byproduct electrical generation yields significant economic benefits over steam production with package boilers and purchase of electrical power.

Potentially, more than 33,000 MWs of additional power could be generated by industrial byproduct power units by 1985, resulting in an equivalent savings of 680,000 barrels per day of oil. It is estimated that this could be achieved with a return on investment of 20 percent or more per year before taxes (ref. 6).

This application has significant potential for reducing environmental impact of thermal and air pollutants, conserving fuel, reducing the overall capital needed for electrical generation, and reducing the cost of producing power and process steam.

The disadvantages of this application are that industry will be required to generate the new capital for the new facilities and will need to upgrade the skills of the boiler plant personnel. However, as the cost of energy continues to rise, it is likely that industry will find that the incentives for generation of byproduct power will outweigh the disadvantages.

The third option, often referred to as integrated production/use facilities or dual purpose energy conversion facilities, has potential for long-term waste heat utilization/reduction. In this application both the energy production facilities and the user facilities are designed for operational compatability, in terms of capacity, load characteristics, and equipment lifetime. These facilities provide opportunities for increasing the efficiency of energy utilization by 10 or 15 percent through optimization of alternative energy blends. These facilities, however, must be large in scale (the equivalent of 1,000,000 lb of steam/hr) to interest utilities in a joint venture.

Development of integrated energy facilities has been limited to a few applications because constraints involving compatibility of production and user systems, the financial risk involved, lack of necessary capital, and inappropriate long-term planning. Hopefully, the economic incentives for integrated facilities in the future will encourage industry, utilities, and government to solve some of the problems which now limit development.

An example of the benefits to be gained from an integrated facility are summarized below. An integrated coal-fired central station designed to supply 600 MWs and 2,000,000 lb/hr of steam at 150 psia, with a 35 percent load factor, could yield an equivalent savings in fuel of 7,000 barrels of oil per day (ref. 6). This savings in fuel would result in a proportional reduction in air emissions and a large reduction in the waste heat discharged.

EPA is initiating a study to (1) examine projected cost of fuel, materials, labor, etc., (2) formulate four promising integrated energy complexes, and (3) assess the economic, environmental and energy conservation aspects of these facilities at the projected cost levels. The project should provide some indication of the environmental benefits and economic viability of these applications.

## OTHER CONSIDERATIONS

The technical feasibility and the economic viability of any application to utilize waste heat or reduce the amount generated will depend on many factors such as:

1. compatability of the supplier and user systems,
2. economic, fuel conservation, or environmental gains,
3. institutional constraints,
4. availability of capital, and
5. geographical constraints.

It is essential that these and other factors be addressed and resolved before a joint waste heat utilization/reduction project is to be successfully initiated.

Each application will have different factors such as fuel availability, fuel cost, site characteristics, distance from production to load centers, availability and compatability of producing and using facilities capital, etc., which must be evaluated on a case-by-case basis. It is expected that each application will have to be designed with specific objectives within fixed technical, economic, and institutional constraints.

## CONCLUSION

Research is needed to indentify and demonstrate feasibility, energy-saving potential, and economics of potential waste heat utilization/reduction applications. Some of the approaches described in this paper are well developed and near commercial application; others are in the infancy stage and need rigorous efforts to evaluate their ultimate potential. The impact of waste heat use and reduction on our nation's energy supply is difficult to quantify based on current methodology. As with many projects, the ultimate impact depends on the degree of successful technology development. However, the potential for significant waste heat utilization cannot be denied because the waste heat already is available in tremendous quantities. As noted previously, unless we take the initiative to (1) better utilize waste heat and (2) improve the efficiency of energy production and utilization, the amount of *waste heat* discharged to the environment by the year 2000 will equal the *total* U.S. energy demand in 1970. Waste heat utilization, by-product electrical generation, and integrated energy production/use complexes will help to reduce the near-term, midterm, and long-term discharge of waste heat, respectively. However, because of the state of development, the complexity of the applications, and the long lead times required, it is necessary for industry, utilities, and government to take action on all three options at this time. The results should yield significant environmental, economic, and fuel conservation benefits.

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# STAGED COMBUSTION IN COMBINED CYCLE SUPPLEMENTARY FIRED BOILERS[*]

D. R. Bartz, S. C. Hunter, and J. K. Arand[†]

*Abstract*

*A scaled laboratory combustion experiment was conducted to determine the effectiveness of staged combustion in reducing nitric oxide present in the combustion air supplied to large diffusion flames. Significant chemical reduction of the inlet nitric oxide suggests the possibility of application to supplementary fired combined-cycle systems as an alternative to water injection as a means of controlling $NO_x$ to anticipated EPA emission limits.*

## INTRODUCTION

One of the more acceptable approaches to adding capacity to existing municipal and regional power networks is that based on the installation of combined-cycle units. They have been favored by many utilities recently because of the comparatively short delivery and installation time, favorable unit cost, and low firing rate. A combined cycle is a combination of open Brayton cycle gas turbines and closed rankine cycle steam boilers and turbines. The components are arranged so that the exhaust of the gas turbines passes through the steam boiler and provides a means of recovering part of the waste heat normally exhausted by the gas turbines. When this heat recovery is accomplished with a convective waste heat boiler only, the combination is designated as an unfired combined cycle. Normally the gas turbine exhaust contains oxygen concentrations in the 15 percent to 18 percent range, which can be utilized as a kind of vitiated air supply with which to burn additional fuel to thereby generate more power than would the unfired boiler. This arrangement is designated as a supplementary fired combined cycle.

Aside from all of the favorable attributes of gas turbines and combined cycles, the gas turbine as built today for power applications experiences difficulty with pollutant emissions. While at present there are no national new-source standards for gas turbines—only local standards in priority I regions—such standards are under consideration by the EPA and have been circulated for industry comment. The standards under consideration for nitrogen oxide emissions (calculated as $NO_2$ at air dilution characterized by 15 percent oxygen) are 55 ppm for gas fuel and 75 ppm for liquid fuel. These correspond to 0.2 lb/MBtu and 0.3 lb/MBtu of $NO_2$ respectively, the current new-source standards for boilers. These standards are sufficiently low that they cannot be met with current gas turbine combustion technology for liquid fuel burning, and the use of natural gas in most regions is only a fond memory. As a consequence, most installations designed to meet regulations as stringent as these are forced to utilize water injection as an $NO_x$ control technique. While this does work, it is costly, inconvenient, and in the long range may cause maintenance or unit life problems. Thus there is a motivation to reduce the $NO_x$ emissions to the levels of the potential new-source regulations by an alternative approach. This was the objective of the analytical and experimental work performed for the Electric Power Research Institute (refs. 1,2) and reported in this paper.

One of the most effective techniques for the control of emissions of oxides of nitrogen in boilers has been the use of staged combustion. The principle involved is to conduct the combustion of most of the fuel in an environment in which there is insufficient air for the fuel to be fully combusted, then to transfer some heat out of the flame prior to adding the remaining air necessary to fully complete the combustion of all the fuel. This achieves two purposes favorable to limiting the formation of oxides of nitrogen. First, it limits the maximum flame temperature reached in the combustion zone, and, secondly, it limits the availability of oxygen during the combustion of most of the fuel. Since the kinetics of the thermal NO reactions are extremely sensitive to the temperature in the flame zone, even a reduction of 100° F or so has a large effect. The presence of an abundance of oxygen atoms is known to have an important effect on the rate and extent to which nitrogen-bearing radicals contained in the liquid fuels are oxidized to nitric oxide, as compared with the competing reactions which convert these radicals to nitrogen molecules. In fully premixed (gaseous or vaporized liquid) flames, these effects are very strong, almost dominant, in limiting the formation of nitric oxide. In the large diffusion flames, which are characteristic of large boilers, much of the combustion goes on at near stoichiometric conditions in a fairly thin flame front. However, there is some premixing that goes on due to turbulent mixing processes in the flame zone.

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[*] Based on work performed for the Electric Power Research Institute, Palo Alto, California, under Contract EPRI 224.

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Thus while staged combustion has not been found to be as effective in these large diffusion flames as it would be in premixed flames, nonetheless the use of staged combustion with liquid fuels has limited NO emissions to 50 percent to 70 percent of what they would have been without staging.

Another effective NO control technique is that of flue gas recirculation in which 10 percent to 30 percent of the flue gas is recirculated into the combustion air. The principle involved is that by loading up the combustion air with a significant concentration of inert species such as $CO_2$, $N_2$, $H_2O$ from the exhaust gas, the energy released from the combustion of a given quantity of fuel with its required oxygen will not yield as high a maximum-flame temperature because of the fraction of the energy soaked up by these inerts in reaching that flame temperature.

The connection between these two NO control principles and combined cycles is that the supplementary firing of the boiler gives an opportunity to take advantage of both with little effort or penalty. The equivalent of flue gas recirculation is achieved in the supplementary fired boiler by virtue of the fact that the exhaust gas from the turbine, when used as the combustion air for the boiler, is diluted with inert species from the turbine combustion process. Operation at conditions in which the oxygen concentration is 17 percent is equivalent to about 30 percent flue gas recirculation. Now, if in addition the turbine exhaust is split into two streams before entering the boiler—one stream fed to the burner windbox (providing 70 percent to 80 percent of the oxygen needed for the fuel), and the other 20 percent to 30 percent of the oxygen (and a portion of the inerts) fed to some overfire air ports (i.e., above the primary combustion zone)—the combustion can be effectively staged. These two NO control techniques working together should be expected to limit NO formation from the burning of the supplementary fuel in the boiler to 30 percent to 60 percent of what it would have been otherwise. While this is attractive, the limitation of the boiler-produced NO would not be sufficient to offset the excessive turbine-produced NO, so as to render a combined system emission below the potential regulation level on a pounds-per-million-Btu basis—not unless the initial fuel-rich zone of the staged combustion could actually chemically reduce some of the turbine-generated NO by stripping off oxygen (i.e., the NO acting as a substitute oxidizer in the absence of sufficient air). The possibility for doing this was suggested by some premixed flame experiments conducted by Wendt et al. (ref. 3).

Thus the objective of the program conducted was to determine the most favorable applicable combined-cycle system operating conditions and then to conduct scaled combustion experiments to determine whether the chemical reduction of the NO could be achieved to a useful extent under practical diffusion flame combustion conditions.

## SYSTEM ANALYSIS—GOVERNING PARAMETERS

System analysis was conducted in order to examine all the pertinent combined-cycle-system design-point variables and their implications with respect to control of $NO_x$ by staged combustion in the supplementary fired boiler. The effects of interest were those of gas turbine exhaust temperature, oxygen and NO content, fraction of gas bypassed around the supplementary burner, air-fuel ratio of the supplemental burner, and power generation split between steam and gas turbines.

A schematic representation of a combined-cycle power plant with staged supplementary fired boiler is shown in figure 1. The plant is comprised of the gas turbine, supplemental burner, steam generator (boiler), and the steam turbine. The system is different from conventional combined-cycle systems only by providing the bypass duct through which a portion of the gas turbine exhaust can be routed around the supplementary burner. By means of this bypass, the burner can be operated fuel rich, and the bypassed oxygen and accompanying inerts can be added downstream to complete the combustion and insure the normal amount of excess (unburned) oxygen in the boiler exhaust stack. Key to effecting a reduction in the boiler-generated $NO_x$ is a loss of heat between the initial fuel-rich combustion and the subsequent addition of the staged oxygen downstream.

Although the system analysis conducted and described in detail in the final report to EPRI on this work (ref. 1) used a 60-Mw gas turbine for illustrative purposes, the results can be interpreted on a relative basis and applied to any size and combination of gas turbines and steam cycles. The steam cycle data was obtained from manufacturer's data for a typical 200-Mw system operating at 1,800 psi, 1,000° F steam temperature. The steam turbine heat rate (exclusive of boiler efficiency) was taken to be 8,170 Btu/kWhr for full-load supplementary-fired conditions. For the unfired conditions where gas turbine exit temperatures in the range of 800° F to 1,000° F precluded 1,000° F steam, a higher heat rate of 10,000 Btu/kWhr was adopted. At intermediate loads between these limits, the heat rate was scaled linearly. A stack temperature of 300° F for the boiler exhaust was assumed constant for all conditions.

The key parameter governing the supplementary combustion is the burner equivalence ratio, i.e., the ratio

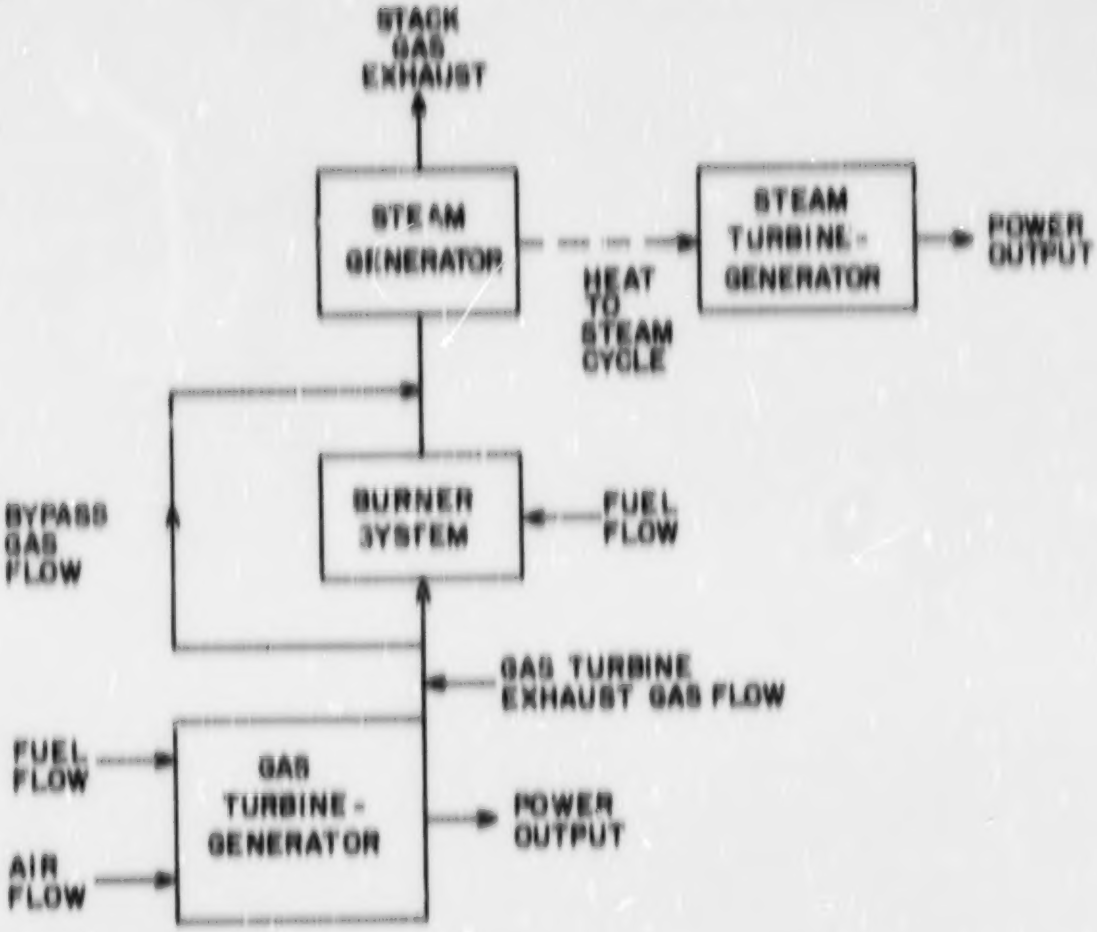

STACK GAS EXHAUST
STEAM GENERATOR
HEAT TO STEAM CYCLE
STEAM TURBINE-GENERATOR
POWER OUTPUT
BYPASS GAS FLOW
BURNER SYSTEM
FUEL FLOW
GAS TURBINE EXHAUST GAS FLOW
FUEL FLOW
AIR FLOW
GAS TURBINE-GENERATOR
POWER OUTPUT

Figure 1. Combined cycle power plant schematic.

of actual fuel-to-air compared with that for stoichiometric combustion, or for a given fuel flow rate, the ratio of stoichiometric air flow rate to actual air flow rate. A gas turbine at full load normally operates at about 300 percent excess air, which corresponds to a 0.25 equivalence ratio. Boilers typically operate with 10 percent to 20 percent excess air or an equivalence ratio of from about 0.8 to 0.9.

If an existing boiler operating at a normal equivalence ratio of 0.9 were to have its air supply replaced with an exactly equal total mass flow turbine exhaust, the boiler burner equivalence ratio for the same fuel flow would increase to over 1.0, i.e., become fuel rich due to the lower oxygen concentration in the turbine exhaust flow, as shown in figure 2. In order to adjust the boiler equivalence ratio back below 1.0 due to safety and efficiency considerations, it would be necessary to reduce the burner fuel flow. For such a system as this, the overall stack (exhaust) equivalence ratio is uniquely related to the combination of burner equivalence ratio and percent of the turbine flow bypassed around the burner. Figure 3 shows that, in the limit of complete bypass of the supplemental burner, the stack equivalence ratio is of course exactly that of the gas turbine. At the other limit of no bypass, the stack equivalence ratio is exactly the burner equivalence ratio. The stack equivalence ratio is seen to vary linearly between these limits. To limit the stack equivalence ratio below 1.0, more

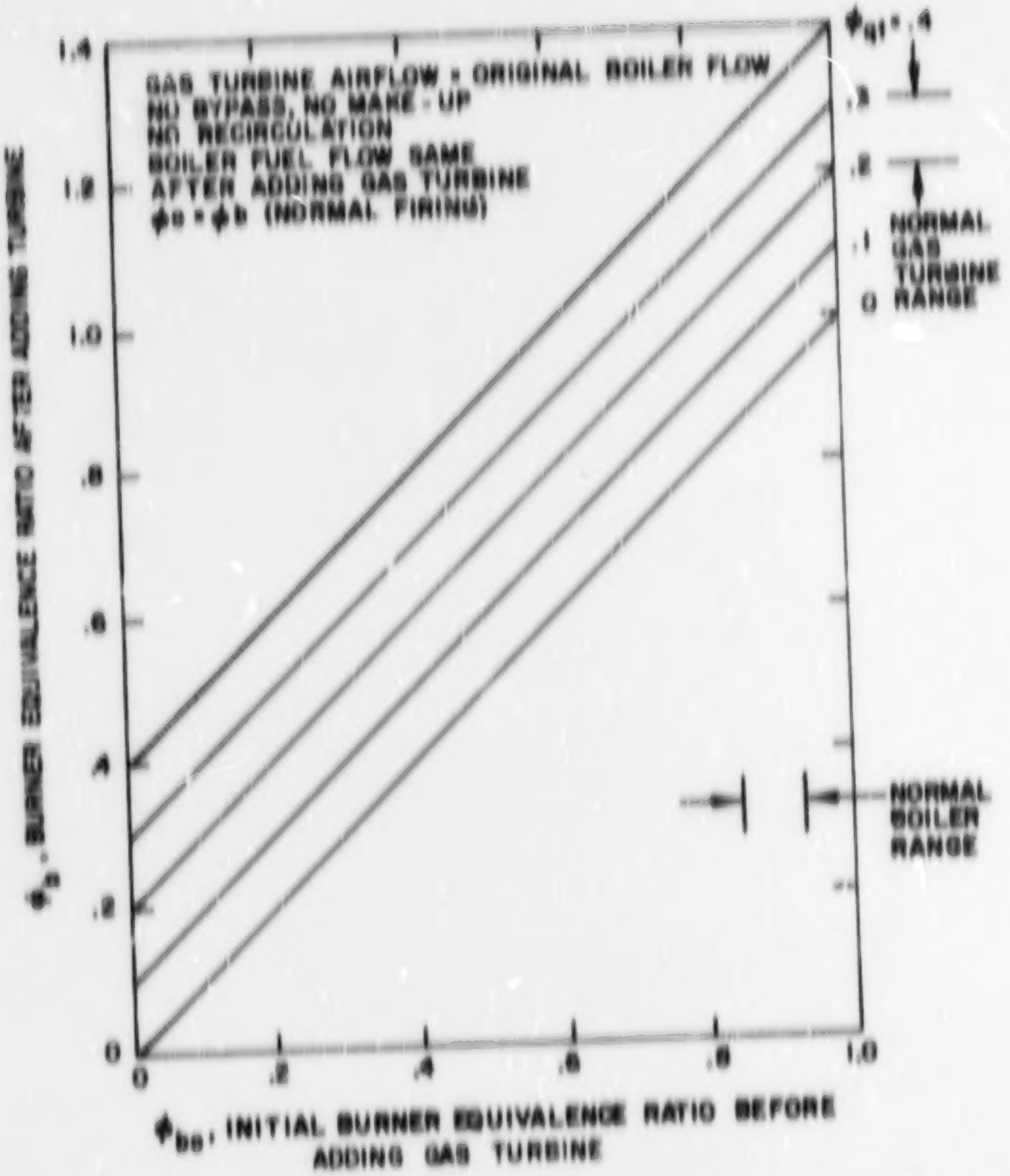


Figure 2. Change in burner equivalence ratio when adding a gas turbine.

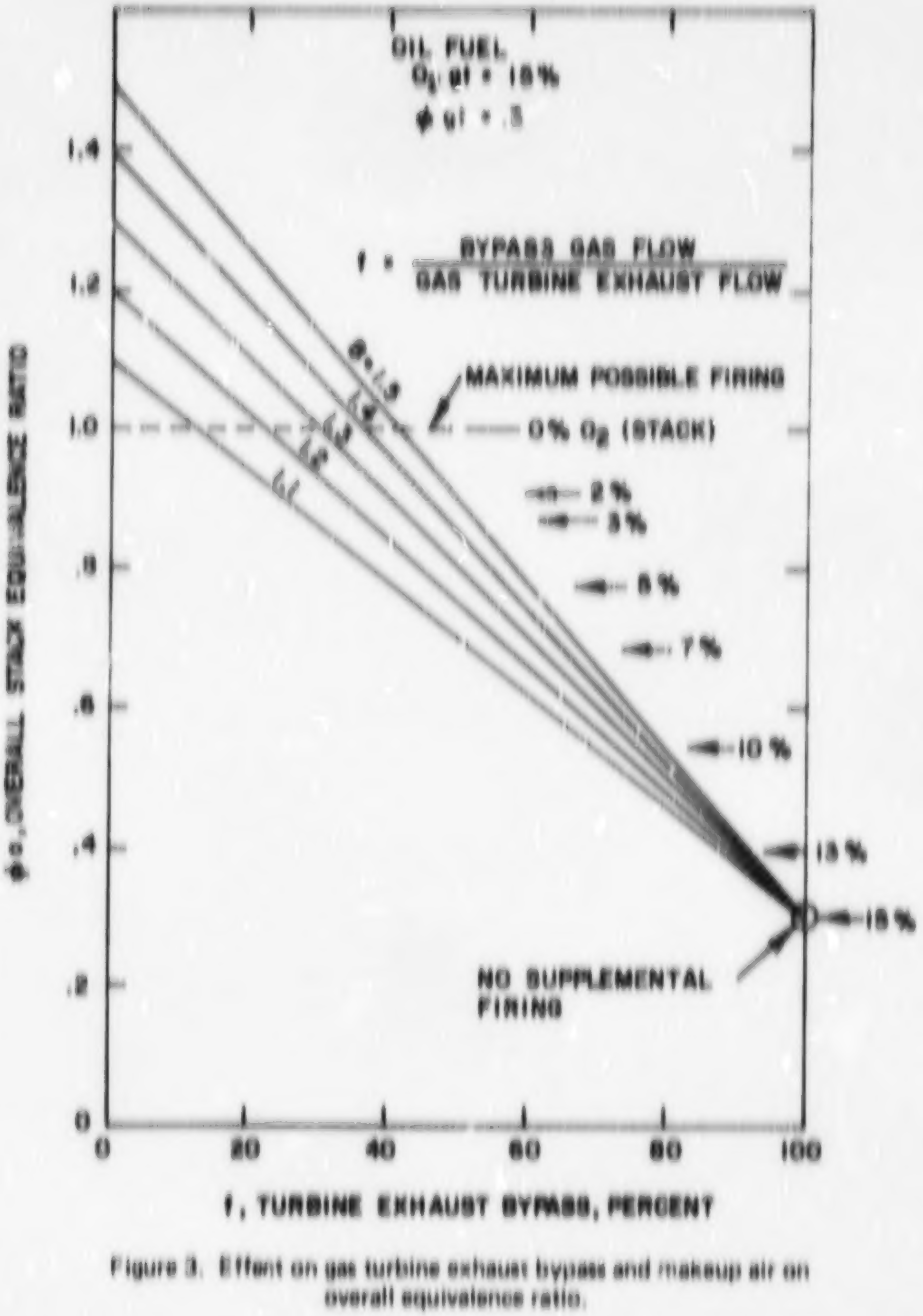


Figure 3. Effect on gas turbine exhaust bypass and makeup air on overall equivalence ratio.

than 50 percent of the flow must be bypassed around the burner to achieve a burner fuel-rich equivalence ratio as high as 1.6.

Finally the payoff variable, that which measures the effectiveness of $NO_x$ reduction, must be defined. In this investigation the so-called NO reduction factor was defined as the ratio of the sum of the NO generated by the gas turbine plus that generated in the supplementary combustion less that leaving the stack all divided by the turbine-generated NO (figure 4). Thus if the NO concentration in the exhaust stack was reduced to that which was generated in the boiler supplemental combustion, the reduction factor was unity, and the turbine NO could be considered to be 100 percent destroyed or chemically reduced. In the experiments to be described, the turbine exhaust gas was a synthetic mixture of $O_2$, $CO_2$, $H_2O$ and NO heated to appropriate turbine exhaust temperature. The NO of course was independently controlled over the range from absolute zero to 100 ppm. By measuring the boiler-burner combustion-generated NO concentration when the turbine NO concentration was maintained at zero, the contribution of the NO generated in the boiler could easily be determined. As will be shown with the data, up to 50 percent of the turbine NO was reduced by the staged combustion.

## EXPERIMENTAL INVESTIGATION

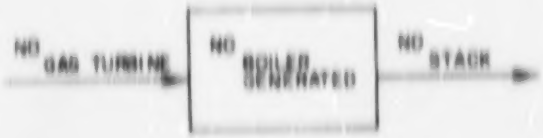
The laboratory test setup utilized for this investigation is shown schematically in figure 5. The simulated gas turbine exhaust was achieved by adding carbon dioxide, nitrogen, water vapor, and nitric oxide to the combustion air supply and then heating the gas mixture to turbine exhaust temperature levels with external ceramic heating elements. This supply of vitiated air was delivered to the 200,000 Btu/hr combustion tunnel, where a portion was fed directly to the single burner and the remainder bypassed around the primary combustion zone, to be added to the combustion flow about 4 diameters downstream. Approximately 50 percent of the burner heat input was lost through the tunnel walls prior to the injection of the bypass air. This loss of heat is essential to the success of staged combustion as an $NO_x$ control technique. By varying the bypass air flow with a fixed burner fuel input rate and fixed total air flow, the equivalence ratio of the primary combustion zone could be controlled. By varying the absolute air flow with a fixed burner fuel flow rate, various ratios of gas turbine power to steam turbine power could be simulated.

Several burner configurations were used to investigate the importance of mixing by the supplemental burner to the anticipated $NO_x$ reductions. During the investigation, the oxygen level and temperature level of the vitiated air were varied to simulate changes in the turbine load. The range of oxygen concentrations tested was from 17 percent to 21 percent, and the range of temperatures from 800° F to 1,000° F. In addition, the NO content of the combustion air was varied over the range from zero, to establish the supplemental burner-only generated $NO_x$, to 100 ppm, a typical level for uncontrolled turbine emissions. The experiments, conducted with both natural gas and light turbine oil fuels, covered a range of fuel flows from 80,000 Btu/hr to 200,000 Btu/hr. The latter rate corresponded to a volumetric heat release rate of 30,000 Btu/hr-ft$^3$ in the 14-in. diameter, 76-in. long tunnel.

In addition to normal fuel and air flow and temperature measurements made with standard techniques, the gas composition measurements were the key to the success of the program. Flue gas samples were withdrawn from three equally spaced uncooled probes, while the vitiated air supply was sampled from a single point. The gas samples were passed through a filter and then refrigerated to condense out water vapor before analysis. A TECO chemiluminescent instrument was used to measure NO, a Beckman electrolytic type sensor to measure oxygen content, a Beckman NDIR instrument for CO. Also, a Beckman hydrocarbon analyzer was utilized. Samples were also drawn occasionally during the program to permit mass spec analysis for trace species such as HCN, $NH_3$, etc.

## TEST BURNERS

The burner that might be selected for an actual combined-cycle supplementary boiler could range in design and mixing quality all the way from a poorly



$$R_f = \frac{NO_{GAS\ TURBINE} + NO_{BOILER} - NO_{STACK}}{NO_{GAS\ TURBINE}}$$

Figure 4. NO reduction factor definition.

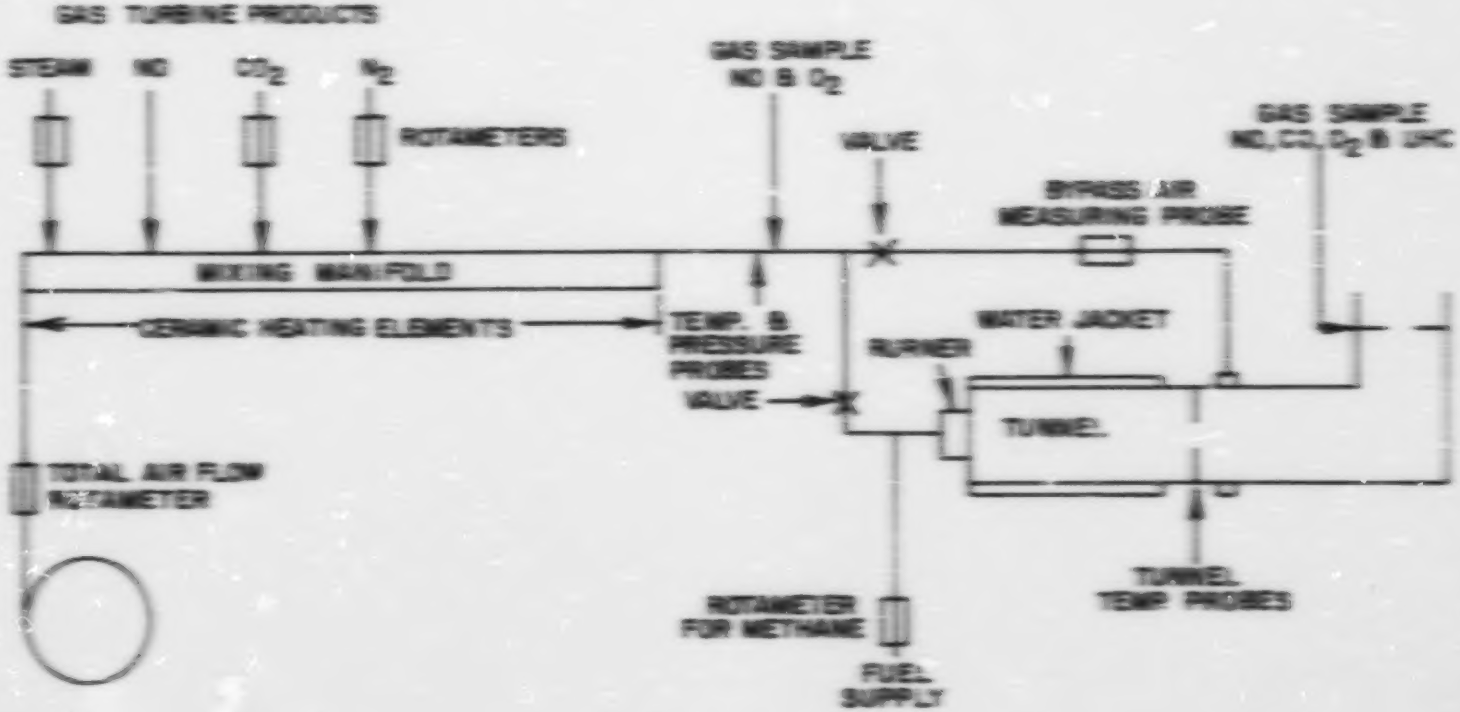

GAS TURBINE PRODUCTS
STEAM
NO
$CO_2$
$N_2$
ROTAMETERS
MIXING MANIFOLD
CERAMIC HEATING ELEMENTS
TOTAL AIR FLOW ROTAMETER
GAS SAMPLE NO & $O_2$
TEMP. & PRESSURE PROBES
VALVE
VALVE
BURNER
WATER JACKET
TUNNEL
BYPASS AIR MEASURING PROBE
GAS SAMPLE NO, CO, $O_2$ & UHC
TUNNEL TEMP PROBES
ROTAMETER FOR METHANE
FUEL SUPPLY

Figure 5. Combined-cycle test setup schematic.

mixed simple flame holder type to a relatively well mixed high swirl burner. Since the burner design is known to have a pronounced effect on NO production, it was desirable to investigate a wide spectrum of burner designs to determine the influence of burner mixing on NO reduction in fuel-rich combustion. One measure of mixing used to characterize aerodynamic turbulence is a mixedness parameter which is proportional to the square root of the ratio of the pressure drop across the burner to the dynamic head of the combustion gas flow in the flame zone. Burners having a high value of this ratio—i.e., high pressure drop and low dynamic head—would have high aerodynamic turbulence and hence good mixing.

The can burner shown in figure 6 is similar to a gas turbine combustor, which is normally characterized as being nearly a totally stirred reactor. Intensive aerodynamic mixing is achieved with the impinging jets of air. The flame stabilization is achieved by the intense gas recirculation zones created by the jet flows. This type of burner typically has a high pressure drop and a low dynamic head, for a mixing parameter value of 351 in arbitrary units.

The nozzle mix burner shown in figure 7 has swirling air flow similar to that of typical utility boiler register burners. The flame stabilization is achieved by both the swirling air flow and the high-temperature zone created by the refractory throat. The mixing parameter is only about one-fifth that of the can burner.

The grid burner, shown in figure 8, is the poorest mixed of the three, with its very low pressure loss and simple fuel injector. This type is used in some combined cycles where the supplementary firing occurs in the boiler air supply duct rather than in the boiler itself. The mixing parameter for the burner tested was about one-tenth that of the can burner.

A problem encountered during the test program was that of flame instability and blowout at many of the test conditions at 17 percent $O_2$ or below. The problem was most severe away from stoichiometric air-fuel ratios. It is not surprising that flame stability decreased with greater vitiation of the combustion air since this is well documented in the literature. Of the burners tested, the nozzle mix burner exhibited the highest degree of flame stability at low oxygen concentrations. Because of this, and because this is the most conventional of the burners tested, results from only this burner will be presented.

## TEST RESULTS

Typical of the results obtained during the program are the data presented in figure 9 in which the NO emissions rate expressed as lb/hr of $NO_2$ is plotted versus burner equivalence ratio. The lower curve with zero NO in the inlet air characterizes the burner generated NO as the burner equivalence ratio is increased up to about 35 percent fuel rich. As is normally expected in burners operating with such staged combustion, the NO emissions dropped to about half the value at near stoichiometric or unstaged conditions. With 100 ppm of NO added to the inlet air supply, the stack emission level would be expected to be about 0.014 lb/hr higher, i.e., the uppermost curve. The actual result, the middle curve, was significantly lower, thus indicating that the fuel-rich staged combustion was actually chemically reducing a portion of the inlet NO to $N_2$ by stripping off oxygen. The more fuel rich the burner was operated (higher equivalence ratio), the greater the fraction reduced, reaching about 67 percent at a burner equivalence ratio of 1.33. Literally hundreds of such curves were obtained (ref. 2) for a wide range of the many variables of interest: fuel, burner type, inlet oxygen level, inlet temperature, burner heat release rate, etc.

A number of such reduction factor data are correlated against burner equivalence ratio in figure 10, and in other such figures of the final report (ref. 2). Each of the correlation curves had a similar shape. Maximum reduction factors somewhat higher than shown were achieved, but generally occurred when there was unacceptably high CO concentration. As can be seen, the results were not sensitive to overall equivalence ratio or to inlet oxygen concentration when oil was the fuel. Curiously, it was found that even without staged combustion, some 10 percent of the turbine NO was reduced by passing through the flame zone.

## APPLICATION OF RESULTS

Results such as these were used to predict just how effective would be the use of staged combustion as an $NO_x$ control technique in supplementary-fired combined-cycle boilers. This was determined as a function of the power generation split between the gas turbine and the steam turbine. To do this it was necessary to compute the net system heat rate and stack equivalence ratio as a function of this power split (as shown in figure 11). Zero on the power split scale represents all gas turbine power, and 1.0 represents all steam turbine. As can be seen, up to a 35-percent power split can be achieved with an unfired boiler, and the addition of that unfired boiler improves the heat rate markedly. In fact, some increase of system heat rate occurs as the power split is taken further, requiring the supplemental firing. The benefit from the supplemental firing from a system NO emissions standpoint is shown in figure 12 which was derived from the experimental data obtained in this

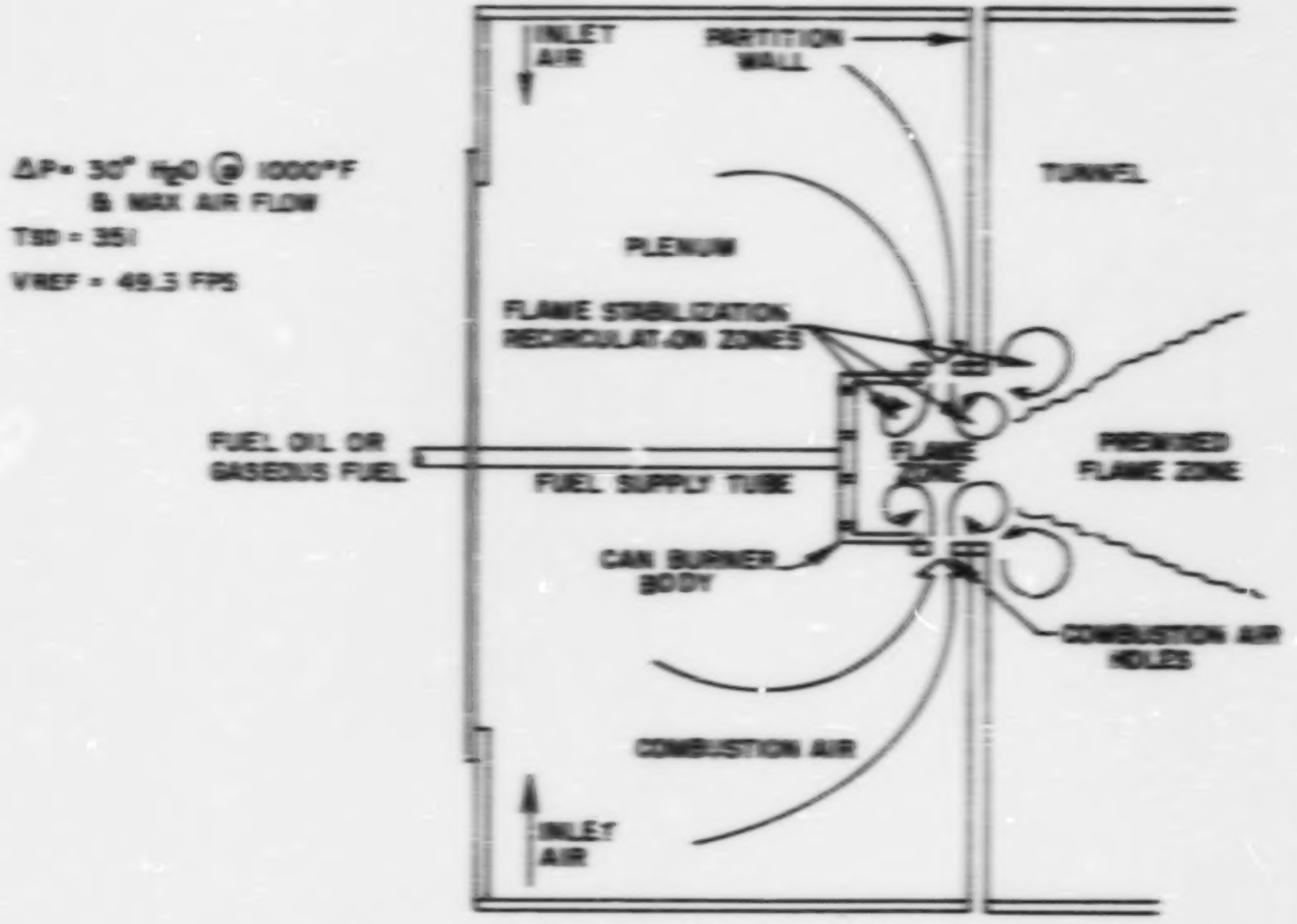

ΔP = 30" H2O @ 1000°F
& MAX AIR FLOW
TSD = 351
VREF = 49.3 FPS
INLET AIR
PARTITION WALL
TUNNEL
PLENUM
FLAME STABILIZATION RECIRCULATION ZONES
FUEL OIL OR GASEOUS FUEL
FUEL SUPPLY TUBE
FLAME ZONE
PREMIXED FLAME ZONE
CAN BURNER BODY
COMBUSTION AIR HOLES
COMBUSTION AIR
INLET AIR

Figure 6. Can burner.

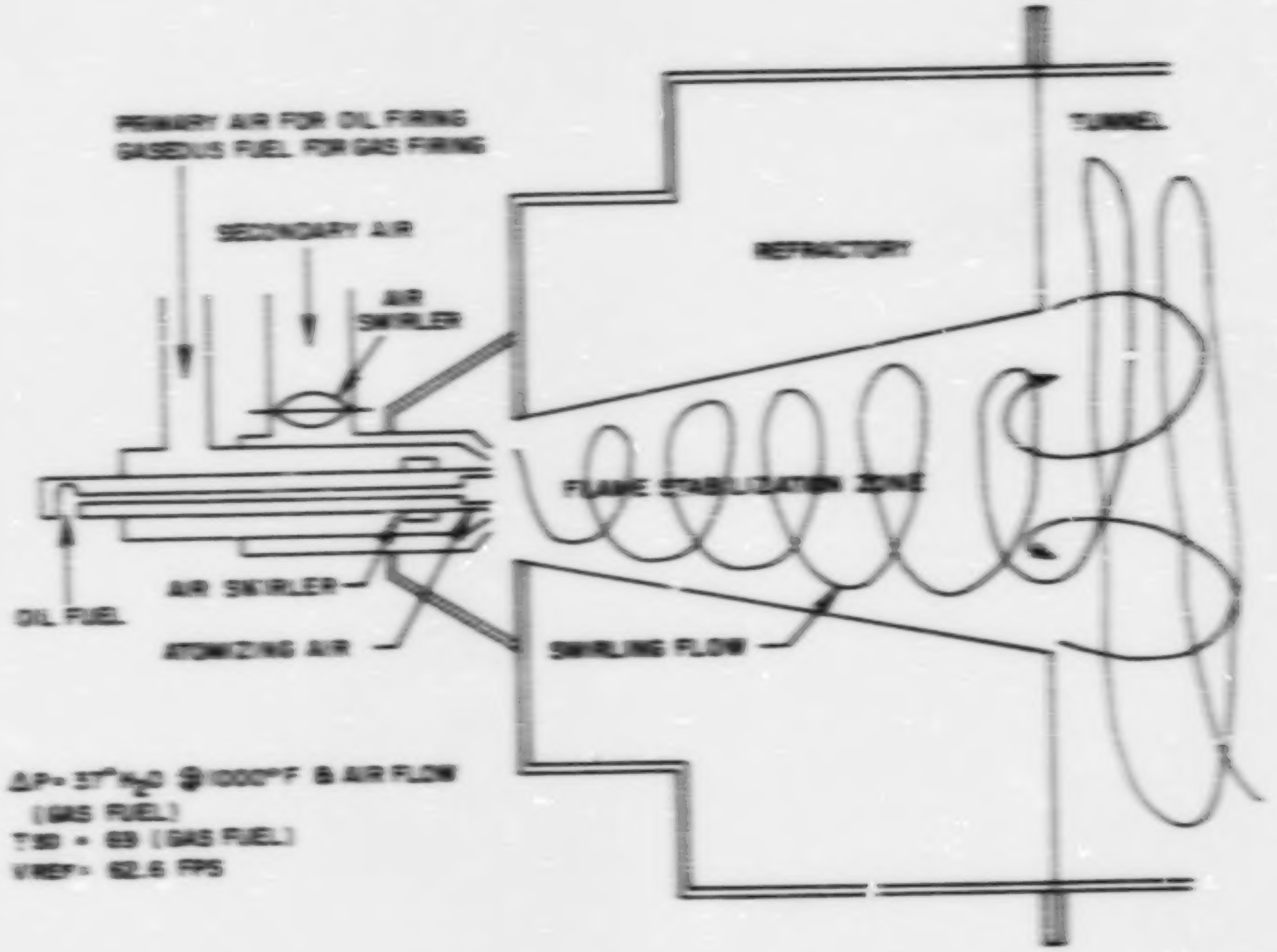

PRIMARY AIR FOR OIL FIRING
GASEOUS FUEL FOR GAS FIRING
SECONDARY AIR
AIR SWIRLER
REFRACTORY
TUNNEL
FLAME STABILIZATION ZONE
AIR SWIRLER
OIL FUEL
ATOMIZING AIR
SWIRLING FLOW
ΔP = 37" H2O @1000°F & AIR FLOW
(GAS FUEL)
T90 = 69 (GAS FUEL)
VREF = 62.6 FPS

Figure 7. Nozzle mix burner.

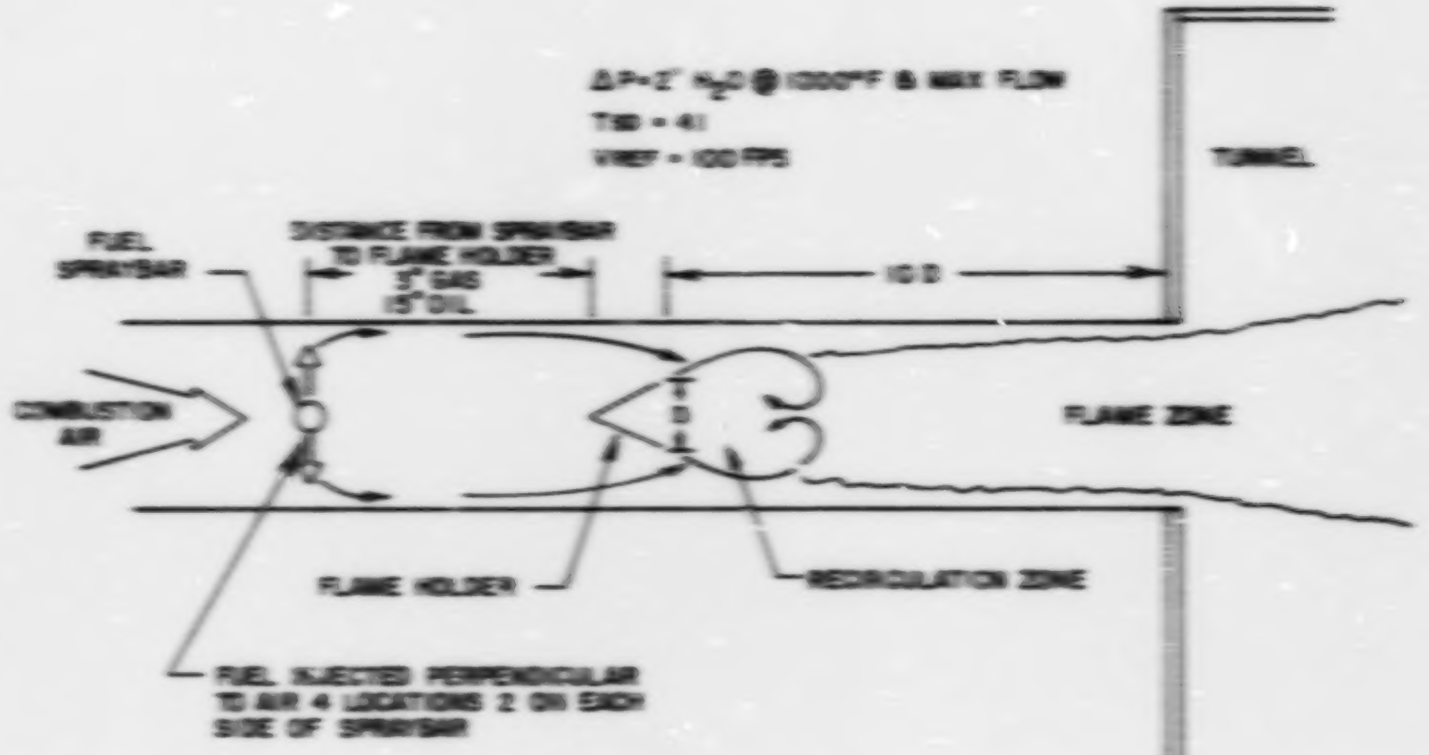

ΔP=2" H2O @ 1000°F & MAX FLOW
T80 = 41
VREF = 100 FPS
TUNNEL
FUEL SPRAYBAR
DISTANCE FROM SPRAYBAR TO FLAME HOLDER
3" GAS
15" OIL
10 D
COMBUSTION AIR
D
FLAME ZONE
FLAME HOLDER
RECIRCULATION ZONE
FUEL INJECTED PERPENDICULAR TO AIR 4 LOCATIONS 2 ON EACH SIDE OF SPRAYBAR

Figure 8. Grid burner

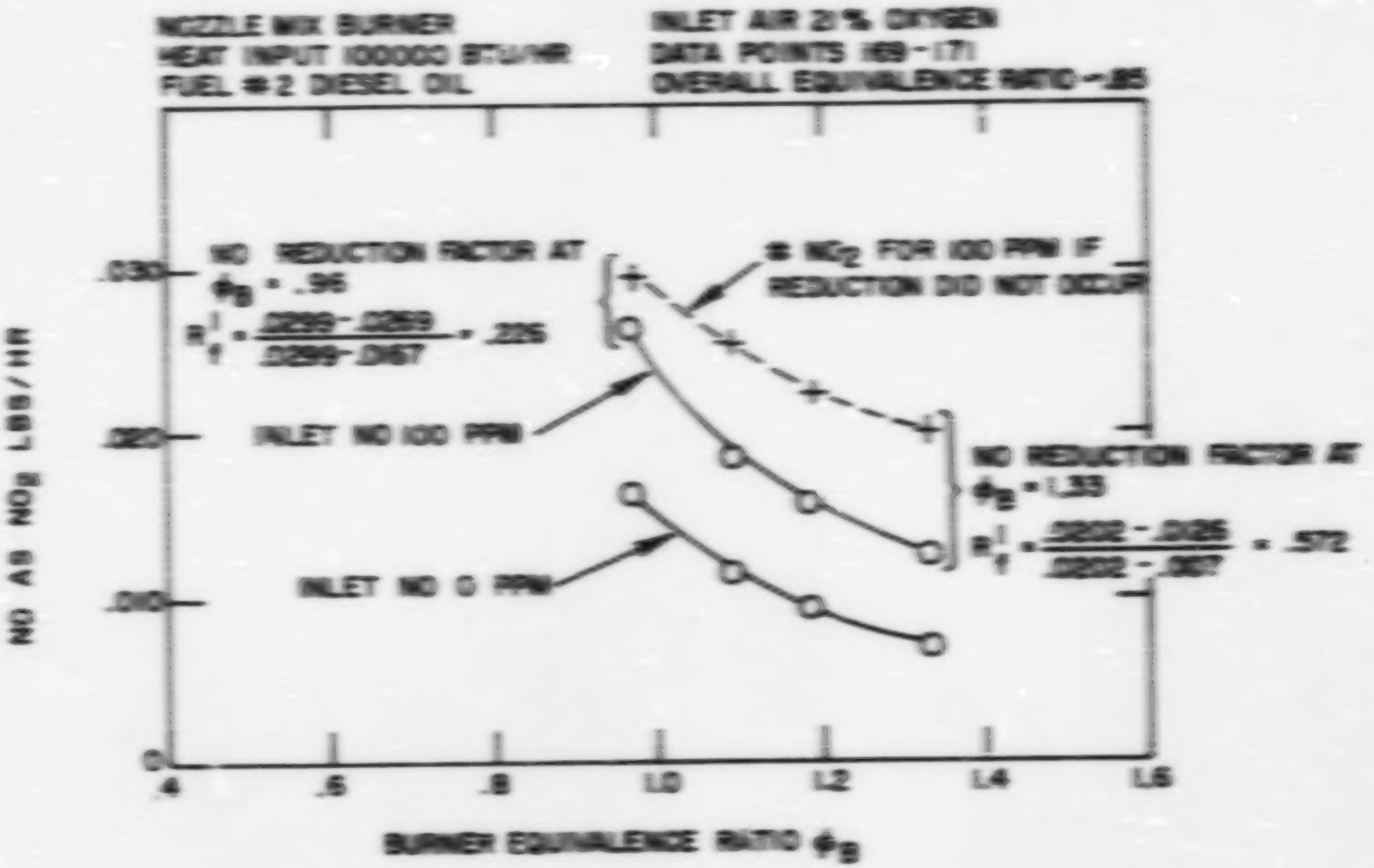


Figure 8. Reduction of inlet NO at high overall equivalence ratio for 21 percent $O_2$ inlet air concentration and #2 oil fuel.

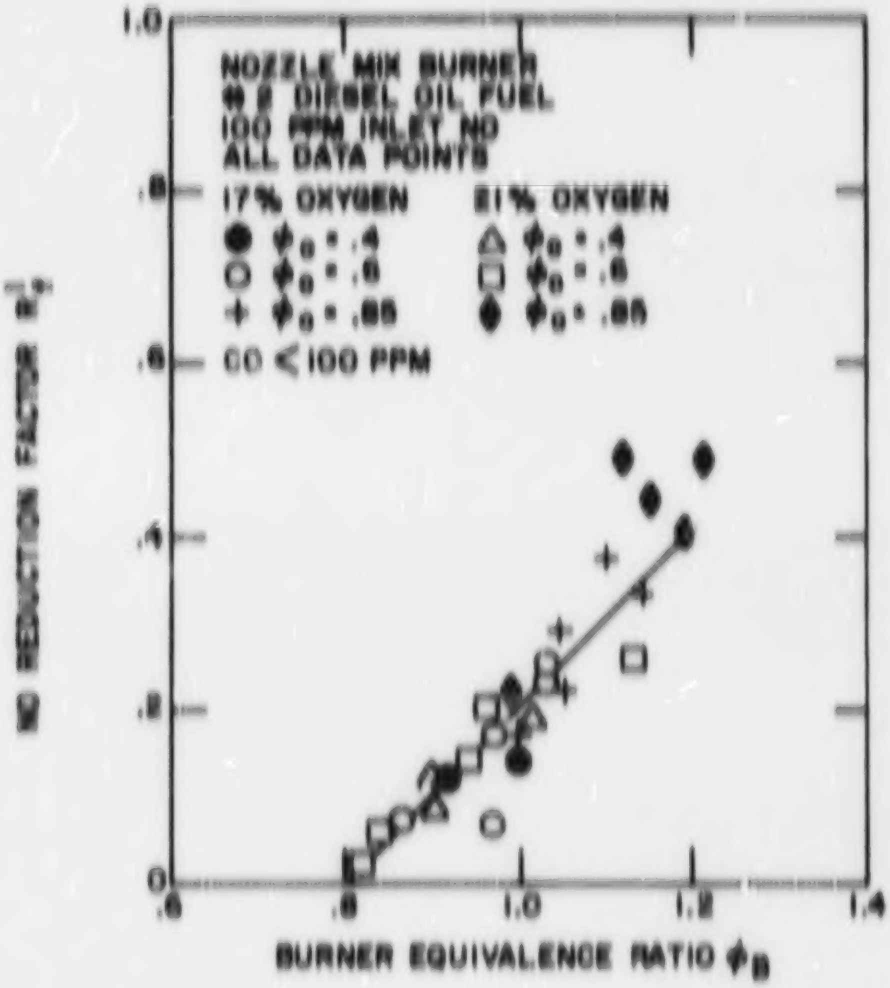


Figure 16. NO reduction factor for #2 oil fuel at all test conditions with stack CO less than 100 ppm.

program, some of which was presented on previous figures. As is seen, the gas turbine emission rate corresponding to 100 ppm is about 0.33 lb/MBtu, somewhat above the anticipated regulation level of 0.3. Some gas turbines without water injection emit considerably higher concentrations. As the power split is taken beyond 35 percent and supplementary firing is used, the system emission level drops rapidly both with the staged combustion and even with normal unstaged combustion. The latter drop is a consequence of boiler-generator emissions being lower for the case considered and the modest (10 percent or so) chemical reduction with normal firing. With staged combustion, the drop in system emissions is significantly greater, dropping to about one third of the anticipated regulation level at a power split ratio of 0.75, which corresponds to one fourth of the system power from the gas turbines and three fourths from the steam turbine.

Such a power split as this is unusual for current new-unit, combined-cycle design practice. The results

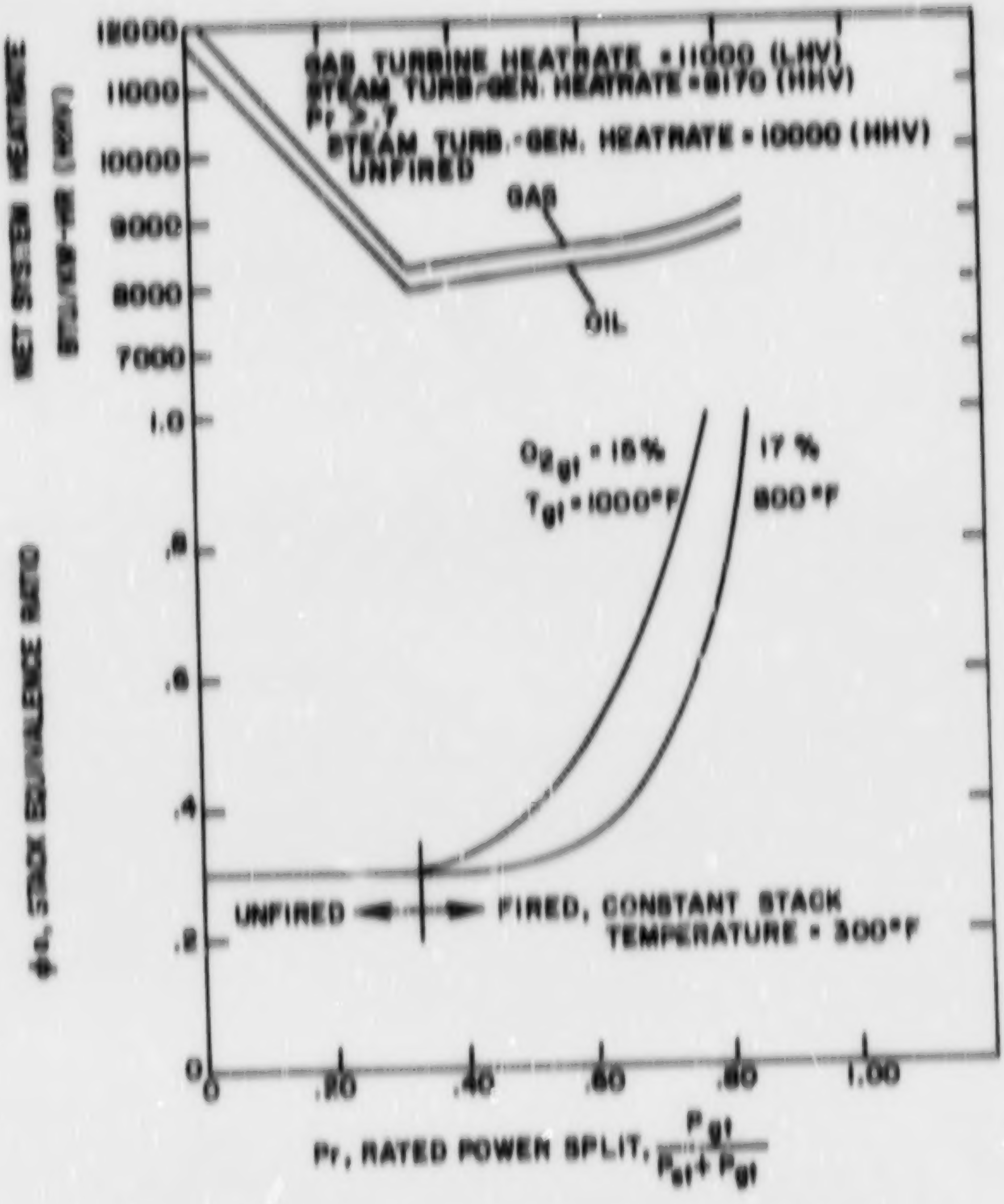


Figure 11. Combined-cycle net heat rate and overall equivalence ratio as a function of power split at design rated load.

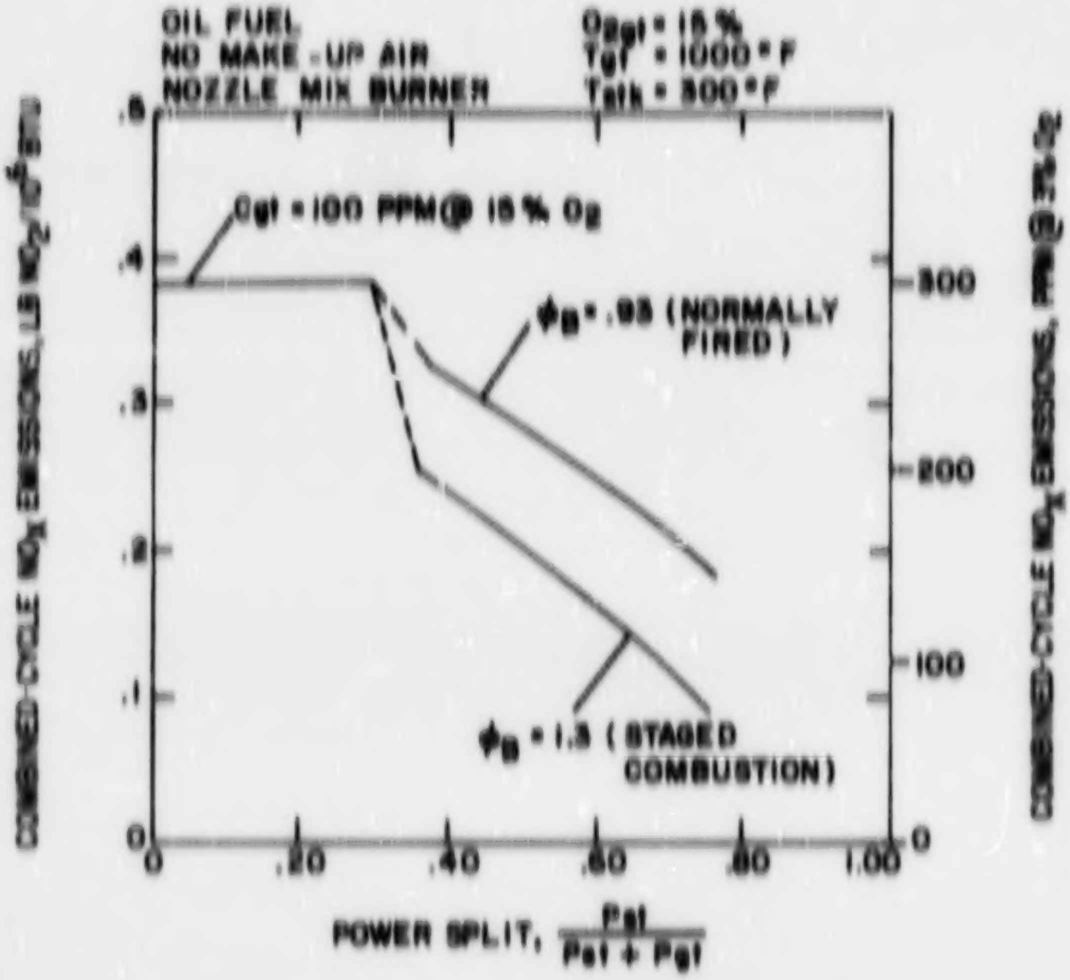


Figure 12. Combined cycle, LB $NO_x/10^6$ Btu, for oil fuel operation.

suggest however a possible way of adding capacity to an existing boiler by repowering with a gas turbine replacing the FD fan and air preheater, thereby increasing total system power significantly at what are likely to be acceptably low NO emissions levels (ref. 4).

Other results are presented in the EPRI report on this work that shows how the combined cycle heat rate and emissions vary with percent of rated power output for several optional throttling modes.

## CONCLUSIONS

The use of staged combustion has been shown through a series of laboratory scale tests to be a promising method for $NO_x$ emissions control in supplementary fired combined-cycle systems over a wide range of system operational conditions. Specifically the results suggest that the use of staged combustion in the supplementary fired boiler may provide a viable means for compensating for gas turbine $NO_x$ emissions in excess of anticipated EPA standards without having to resort to water injection. It remains for full-scale tests to be conducted to confirm these results, although there is no reason to believe that it will not be as effective at larger scales. The $NO_x$ reduction effectiveness was found to be the highest at the highest power splits (more steam turbine power than gas turbine power) where the turbine exhaust is fired to the minimum practical oxygen concentration. Reduction of up to 55 percent of the turbine-generated $NO_x$ was found to be achievable under practical operating conditions with diesel oil fuel. The effectiveness of the staged combustion was found to be dependent on the fuel type, burner, and firing rate much more than on any of the gas turbine exhaust conditions such as temperature or oxygen concentration.

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# ELECTRIC POWER TRANSMISSION MODES, MEANS, AND STYLE

Robert W. Flugum[1]

*Abstract*

*Transmission of electric power faces a challenge in the future as the Nation shifts to a more electric economy to conserve scarce fossil fuels. The modes of transmission must be expanded in power transfer capability, and environmental aspects and efficiency must be considered as essential elements in design and installation practices.*

## INTRODUCTION

Electric power has become, over the last seven decades, the most important single technology maintaining our way of life. It is destined to become even more dominant as its inherent flexibility permits for electricity production use of basic energy sources that do not contribute to the undesirable attrition of scarce fossil fuels. Critical as electric power is to our Nation's needs, many practices and characteristics associated with its generation, transmission, and distribution have come under fire as not being responsive to today's concerns about the environment and man's well-being. Further, as the demand for electric energy inevitably will exceed industry's supply, the need for conservation in its usage must be addressed.

## GENERAL

If the premise is accepted that our society, as we know it today, could not be maintained without electricity, then it follows logically that we must generate, transmit, and distribute that electricity. Without being totally defensive, however, we find that our populace, at least in part, raises strong objections to any intrusion from the necessary construction of electric power installations—in particular, generating plants and transmission lines. There are undoubtedly historical, political, economical, and social rationales for this negative attitude, most of which could be effectively debated. The positive approach, however, is to address the questions directly, using research and development programs where necessary, and education where the debate is philosophical rather than technical.

In particular, environmental concerns about high-voltage (HV) transmission had been limited, prior to 1970, to aesthetics, landscape disturbances, and plant life effects, with only radio and television interferences as direct electrical considerations. More recently, it has been suggested that possible biological consequences from the presence of electric fields under high-voltage transmission lines may appear. If true, this could pose a hazard to the public and to the electrical HV transmission worker. The public is now also aware of low-frequency noise generated by HV transmission lines particularly during fog or drizzle. Such psychoacoustic irritations have been cited in intervenor actions against new construction proposals for 765-kV transmission lines.

Attention is also being focused on the impact of electric power transmission on our national goals of energy conservation. In the power system loss structure, only 10 to 15 percent is found in the transmission system from generator terminals to ultimate user. However, even if only direct losses are considered, because of the vast amounts of power to be transferred, a 25 percent improvement in transmission efficiency would have a significant effect in direct energy conservation. If, in addition, conservation is expanded in definition to include the energy saved by reduced use of materials and improved manufacturing techniques, the impact of successful research in transmission equipment and methods can yield further important savings.

## ELECTRIC POWER TRANSMISSION MODES

In broad categories, electric power transmission can be described as either overhead or underground—with "on" or "over" ground considered part of the latter. Which mode is used depends on a number of factors, among them capacity requirements, system voltage, distance, siting, terminal location, economics, and environmental constraints. There are many situations where there is no choice. For overhead, these would be applications requiring thousands of megawatts to be transferred over hundreds of miles. On the other hand, for overwater power transfer from 2 to 20 miles, underground types of cable are usually the only practical transmission scheme.

It is generally assumed that underground transmission constitutes a large part of the total of electric power transmission lines in the United States. Two of the above factors keep this from being true: economics and power capacity requirements vis a vis overhead transmission. Table 1 illustrates the disparity in installed miles and capacity when comparing the two. In the case of underground at 765 and 1,100 kV alternating current (a.c.) and overhead at 1,100 kV a.c., the loadings shown have not actually been attained; they are considered, however, within the capability of present-day technology.

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While use of underground cables at distribution voltages is at a parity with overhead construction in many areas of the country, no such trend is evident in transmission. Even the most recent line construction figures in transmission voltages show a ratio of overhead to underground of about 100:1, comparing mileage of each installed. This is particularly true at the higher voltage levels, where high-power transfer capabilities are absolutely necessary and where, as can be seen in table 1, there are no underground installations.

This almost total reliance on overhead transmission, while undeniably affected by cost and power capacity, also reflects a large element of design deficiency and, probably more important, past application practices and needs.

For example, if the underground cable circuits in the United States were identified as to location and application, it would be found that over 80 percent of the installed circuit miles are in two or three east coast utilities where population density and siting restrictions have literally forced the use of underground, at whatever costs. Further, the vast majority of these circuits are less than 10 miles in length and carry no more than 100 MW per circuit. In effect, then, for long, high-capacity circuits, overhead is the only mode of transmission utilized by the electric operating companies.

The goal of the research effort in underground cables is, in reality, to produce a credible alternative to overhead transmission, so that where an application demands underground, capacity and voltages can be comparable and costs can be more nearly equal. Such an alternative does not exist today.

In that research, a considerable percentage is devoted to development of the cellulose and synthetic cables for the higher transmission voltages—that is, 500 and 765 kV. There is no hope, however, that such developments, even if successful, would be used on circuits for loads greater than 1,000 MW, over any distance greater than 20 miles. This must be left to the new technologies in underground—gas cables, cryoresistive cables, and superconducting systems.

Table 1. Per circuit capacity and installed miles of transmission lines in the United States[a]

| Voltage rating | Capacity (MW) | | Miles Installed[b] | |
|---|---|---|---|---|
| | O.H.* | U.G.* | O.H. | U.G. |
| 138,000 | 400 | 400 | 159,500 | 1900 |
| 230,000 | 900 | 700 | 54,500 | 200 |
| 345,000 | 1350 | 900 | 25,500 | 200 |
| 500,000 | 2000 | 1200 | 12,300 | - |
| 765,000 | 4000 | 2000 | 1,400 | - |
| 1,100,000 | 7000 | - | - | - |

[a] From a report by IEEE T&D Committee.

[b] As of 1-1-75.

*Legend: O.H.--overhead; U.G.--underground.

Of these, the most promising from a standpoint of economics and loss reduction are gas-insulated cable systems and superconducting transmission lines, both of which could be installed under or on ground.

## ELECTRIC POWER TRANSMISSION MEANS

There are several electrical parameters that must be considered in comparing transmission modes, and they do not react or affect the critical limits of each mode in the same way.

### *Surge Impedance*

Overhead line surge impedance varies from 500 ohms for 145-kV lines to 250 ohms for 1,200-kV lines. For underground conventional cables it varies from 25 to 35 ohms and is relatively independent of system voltage, while for gas cables it is about 60 to 70 ohms. The surge impedance is a function of the line dimensions, and construction numerically is equal to L/C. It affects power transfer capability and line transient characteristics.

### *Line Capacitance*

There is an inherent capacitance to ground for any energized transmission line. The capacitance varies from about .012 to .025 μfds/mile for overhead lines as a direct function of configuration and distance from ground. For underground conventional cables it is about 0.6 μfds/mile regardless of voltage. Gas cables have a lower capacitance, between 0.1 and 0.2 μfds/mile, because the gas dielectric constant is unity. The amount of compensation required is directly related to line capacitance.

### *Loading or Power Transfer Capability*

For overhead lines, loading is thermally limited only at 230 kV and below. At the higher voltages, system stability, as determined by surge impedance loading, is the limiting factor. Equally important is the fact that conductor size and number of conductors per phase is a function of corona start voltage limitations. At 345 kV and above this usually results in multiple conductors per phase; the conductors are thermally capable of carrying several times the normal load current. At the lower voltages, because there are many short lines, the systems are solidly tied together, and this theoretical load limit can be and is exceeded, sometimes by a factor of 10. Because of the length of 765- and 1,200-kV lines and the magnitude of power transferred, operating loading must more nearly conform to the theoretical; otherwise, steady-state stability would be imperiled. For cables, surge impedance loading is not important, as loading is always determined from thermal limitations.

These parameters interact when considering the appropriateness of various transmission modes for different applications, since they affect power transfer capacity and reactive compensation requirements. The data in table 2 compare reactive compensation requirements for the various systems and the costs for the same systems in terms of power delivered per mile. The figures indicate that parity with overhead can be approached by gas-insulated cables in the higher voltages, and with superconducting systems at 345 kV and below. If these systems are developed as now projected, we will have the alternates for overhead transmission for use where the situation demands it.

In comparing transmission modes, only a.c. has been considered here, because it represents the most common type of power system today. A comparison of a.c. and direct current (d.c.) as power transmission modes would expand this paper beyond the prescribed limits. Suffice to say that use of d.c. reduces losses directly, and d.c. overhead greatly minimizes environmental impact both from a visual and electric field standpoint. Further, one of the real constraints in the use of long underground a.c. cables is reactive compensation requirements, as shown in table 2. For d.c. cable there is no added reactive compensation, which greatly improves the economic compatibility with overhead.

There is still a considerable cost differential in station or terminal costs between HV a.c. and HV d.c.—on the order of eight to one. This restricts its use with the present-day technology to very long, high-capacity systems, or special situations where stability considerations or long underwater ties dictate the use of HV d.c. regardless of cost.

## ELECTRIC POWER TRANSMISSION STYLES

To associate style with any part of electric power transmission is almost ludicrous to those who consider it the "bete noire" of environmental offenders. Yet, it is only aesthetically that transmission line design can be factually faulted. Indeed, using underground transmission, there is practically no permanent upsetting of the environment. This is the very reason it has been suggested, albeit naively, that all electric power should be transmitted in that mode. The incremental cost of this substitution, i.e., underground for all new construction, would be $20 to $30 billion annually (ref. 1). This is more than the estimated one-time cost of cleansing our rivers and lakes, a task considered too huge to finance, even though the latter is one of the most

Table 2. Comparison of costs for various transmission modes

| | kvar/MW- | | | | $4 MW-MI | | | |
|---|---|---|---|---|---|---|---|---|
| KV MAX. | OH* | UGI* | GIS* | SC*† | OH | UGI | GIS | SC |
| 145 | .25 | 8 | | | 500 | 2,000 | -- | 600 |
| 242 | .33 | 10 | | - | 275 | 1,200 | -- | 400 |
| 362 | .55 | 12 | 1.25 | | 220 | 1,000 | 350 | 250 |
| 550 | .88 | 14 | 1.5 | 6 | 210 | 600 | 300 | -- |
| 800 | 1.5 | 20 | 2.5 | - | 130 | 500 | 230 | -- |
| 1,200 | 2.3 | | 3.3 | - | 110 | - | 200 | -- |

*Legend: OH--overhead; UGI--underground gas insulated; GIS--gas insulated system; SC--superconducting.

†Rough Estimate, source Brookhaven National Lab.

onerous and distasteful results of man's careless use of nature.

The environmental effects of overhead transmission can be separated into two classes, the known and the presumed. In the first category are such well-documented and studied effects as radio noise, television interferences, and audible noise. These are all the result of corona that may appear on a line during foul weather operation, or from breakage or damage to line insulation, hardware, or conductors. Radio and television interference problems, while responsible for the majority of complaints, are still small in number relative to the many miles of installed transmission line. They can occur on lines of any voltage level, and are usually cleared up by local maintenance or filtering.

Audible noise, on the other hand, although an even rarer problem in the past, has the potential of being a real barrier to the use of higher transmission voltages. This is because the probability of annoyance increases significantly with the higher voltages, and because psychoacoustical responses to such steady noises, where ambient levels are of similar magnitude, are an unknown quantity. These direct effects of corona are being studied, particularly the audible noise. Acceptable limits, as determined by research programs, will be attained by proper line construction.

From the aesthetic or visual aspect there is also much to be gained from research. Although the traditional lattice structure, against which most outcrys have been directed, is still the most efficient in terms of material usage, it represents to the public the outmoded, the archaic, and the undesirable in structural design. While the utilities have made considerable progress in tower design—evident from many unique structures, primarily using steel poles and curved graceful crossarms—no attempts have been made to integrate the newest of insulating materials into designs of conductor support systems. These new materials have strength-to-weight ratios more than an order of magnitude greater than the traditional materials such as porcelain and glass, and thus invite use of totally different concepts in line support structures. Transmission line support systems using these materials, and designed with minimum environmental impact as a major criteria, may some day inspire as much admiration as certain other lattice structures supporting catinaries and cables crossing our rivers and waterways. To attain this millenium, however, it will probably be necessary to convince the public that electric power is as important to them as the automobile and getting home from work every night.

In the other category of environmental effects are those which have biological implications. These basically concern the effect of the electric fields under high-voltage lines on life forms, either human, animal, or plant. However, one corona-induced consequence, ozone, has also been included as a possible hazard. The latter concern should have long ago been laid to rest, since the measured ozone production of transmission lines, even when operating at 1,500 kV, has been shown to be an order of magnitude less than that normally present in the atmosphere from natural sources.

Whether electric fields produce biological effects in a body or plant under a line remains to be determined. The question is a classic example of having to prove the negative since there are no known cases where either physiological or psychological damage has been documented. This includes not only casual public exposure, but also farmers working fields under lines, and utility maintenance workers regularly exposed to rather high electric fields. Nevertheless, it would be foolhardy to say that no problem exists. One merely has to remember how nervous a person becomes in a hotel or home where the humidity is so low that a harmless spark discharge occurs every time another object is touched. That there is psychoelectrical response is undeniable. This can occur both under transmission lines with certain atmospheric conditions and with a high enough field at ground level.

The electric utilities have, until a few years ago, maintained a head-in-the-sand attitude about the possible biological effects of HV transmission. This, of course, should not be tolerated. It is a responsibility of the industry and the government to prove that no hazard to the public exists under high-voltage lines, either those in operation or those contemplated for the future. This can be done with well-organized and controlled experiments both in the laboratory and under operating lines. We cannot afford to build 1,200 kV lines and fence in the right of way as we do interstate highways. The overhead transmission lines of the future can be designed so that field strengths on the ground are at levels that are safe, presenting no danger, seen or unseen, to human, animal, or plant life. Indeed, we may find that, as with X-rays or alcohol, a little electric field is beneficial.

## CONCLUSIONS

The transmission of electric power is as much a mainstay of our form of life as our highways, railroads, and waterways. Transmission lines are now and will even more in the future be essential to success in attempts to conserve our scarce fossil fuels, since only with extensive transmission facilities can the needed shift to a more electric economy take place.

In the transmission system itself it is possible to conserve energy directly by reduction of losses through use of higher transmission voltages, better materials, and more efficient cable systems. The choice of whether to use overhead or underground circuits is not only one of economics but also of technology and the basic characteristics of each system. The systems of the future will be more composite, including both overhead for long-distance power transfer through sparsely populated or recreational areas, and underground where urban areas must be traversed, converting from one mode to the other on a one-to-one basis both in voltage and power capacity.

Underground circuits have a minimum impact on the environment, in that there is only a temporary disruption of the ground during installation. Overhead transmission has a number of effects on the immediate area around and under the lines. Proper and imaginative design of these lines can produce installations presenting minimum consequence to the environment no hazard to the public.

## REFERENCE

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# GEOTHERMAL ENERGY DEVELOPMENT[*]

Paul Kruger[†]

## Abstract

*Projections of electrical energy demand over the remainder of this century indicate the need for greater reliance on energy resources other than oil and gas, even with improved technologies for their increased extraction efficiency. Several alternate strategies are being considered to reduce the apparent need for increased oil and gas import. Among them are: conservation in the form of improved utilization efficiencies; synthesis of fluid fuels from abundant coal and oil shale resources; development of advanced electric energy generating systems, such as breeder, thermonuclear, and solar conversion reactors; and increased utilization of underdeveloped resources, such as geothermal heat, solar thermal energy, and combustible biological and waste products.*

*It is estimated that improved efficiencies in end use can reduce energy consumption in the year 2000 by some 25 percent compared to the strategy of no new initiatives. Replacement of this demand by synthesis of fluid fuels from coal and oil shale could reduce substantially the levels of oil importation. Intensive electrification to meet the same demand would require maximum near-term use of abundant resources of coal and uranium and eventually the advanced electrical generating technologies. Geothermal energy might play a small but significant role.*

*Each of these energy sources has its own spectrum of technical, economic, environmental, and social problems which determine the magnitude and time scale of its contribution to the future total energy supply, either as a substitute for fluid fuels or as an alternate source of electricity. Examples of underdeveloped energy resources are oil shale for the production of oil and geothermal heat for the production of electricity, for which status evaluations of their technical, economic, environmental and social problems are available.*

## INTRODUCTION

The Nation has embarked on an aggressive program to develop its indigenous resources of geothermal energy. For more than a decade, geothermal energy has been heralded as one of the more promising forms of energy alternate to oil and gas for electric power generation, but during the last 15 years, the total capacity in the United States has reached 502 MWe, about half the size of a single modern nuclear power plant. And yet, the United States, especially its Western and Gulf Coast States, is believed to possess a vast resource base of geothermal heat at depths up to 3 to 10 km. Many estimates of these potential resources suitable for the production of electric power have been published, and they range over a spectrum of more than a factor of 100. This variation suggests that the potential is essentially unknown.

Table 1 gives a range of published forecasts for the year 1985 and the equivalent potential in number of 1,000 MWe power plants and in oil consumption in millions of barrels per day. In view of the estimated construction of about 200 to 250 nuclear power reactors by 1985-90, the pessimistic forecasts clearly show that the contribution of geothermal energy to the Nation's energy supply may indeed be small. The optimistic forecasts represent more than 15 percent of the total electric power requirements estimated for the year 1985. The Task Force for Geothermal Energy, in the Federal Energy Administration Project Independence Blueprint report of November 1974, established a national goal for 1985 of 20,000 to 30,000 MWe, the latter value representing an equivalent energy supply of 1 million barrels of oil per day. This goal was clearly a compromise between what is worth a national effort and what might be realistically achieved. The potential for adding or replacing the equivalent of some 25 nuclear power plants or for conserving 1 million barrels of oil per day should be an adequate incentive for the Nation to accelerate the development of a viable geothermal industry.

A puzzling enigma appears. If the potential resource base of geothermal energy is so vast, why has significant utilization not occurred? The entire U.S. production of electric power from geothermal resources occurs at one location, the Geysers in California, where, over a 15 year period starting in 1960, generating capacity has grown

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[*] This presentation was based on reports prepared during Leave of Absence 1974-75 with the National Science Foundation and the Energy Research and Development Administration.

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Table 1. Forecasts and national goal for development of U.S. geothermal resources

| | Pessimistic forecasts | National goal 1985 | Optimistic forecasts |
|---|---|---|---|
| Electric and thermal energy capacity (MW) | 2000-4000 | 20,000-30,000 | 182,000-400,000 |
| Equivalent in nuclear reactors (No. 1,000-MWe units) | 2-4 | 20-30 | 182-400 |
| Equivalent consumption of oil ($10^6$ bbl/day) | 0.07-0.14 | 0.7-1 | 6-14 |

from 12 MW supplied by Unit No. 1 to the total of 502 MW attained with the startup of the 106-MW Unit No. 11 in May 1975. The Geysers is the largest geothermal electricity generating station in the world. The entire world-wide capacity of electric power generation by geothermal resources is slightly more than 1,000 MW, the equivalent of the capacity of a single modern nuclear power plant.

Utilization of geothermal fluids for thermal energy in the United States is almost negligible. And yet throughout the country, fossil fuels are consumed in large quantities to boil water for heating and electric power generation, both at very low thermal efficiency. Some countries already use geothermal fluids for thermal energy, notably Iceland, where municipal heating is an important utilization. Several countries, responding to increased public awareness that future supply of fossil fuel may be very limited, are examining the potential use of indigenous thermal waters for industrial and municipal heating.

How is this enigma to be solved; how is the United States (and other countries), endowed with potentially bountiful geothermal resources, going to develop these natural resources as a significant contribution to its energy supply? The attainment of a national goal to contribute an equivalent of 1 million barrels of oil per day from geothermal resources clearly requires accelerated development of a geothermal industry capable of providing 20,000 to 30,000 MW of electric power and thermal energy in the next 10 to 15 years. And this objective will require a national effort to accelerate and coordinate development in three parallel tasks: (1) the discovery, proving, and extraction of geothermal resources to provide a significant supply of hydrothermal fluids for direct utilization and to produce more than $5 \times 10^{12}$ kWh of electricity over the amortization period of the investment in resource development and power plant construction, (2) the technology to convert the resources as found in its various natural forms and qualities into electricity, and (3) the removal of unnecessary institutional constraints to the rapid development of a cost-effective and environmentally acceptable industry.

A major factor which helps create the enigma of vast resource base and little utilization is the variability of geothermal resources. The geothermal energy cycle, although simple compared to other alternate energy sources, is actually complex in that geothermal resources occur in many types of geologic, thermodynamic, hydrodynamic, and chemical quality. As a result, the major problems in the energy cycle vary by type of resource. Table 2 lists the key aspects of the cycle from exploration to utilization that must be evaluated for each type of resource.

Several general reviews of the state-of-the-art of geothermal energy resources and technology are listed as references 1-8. One is the proceedings of the 1970 United Nations symposium on the development and utilization of geothermal resources. Another is the 1973 compilation of an ad hoc working group convened by UNESCO. A general introduction to geothermal energy is the proceedings of the American Nuclear Society conference on geothermal resources, production, and stimulation held in 1972. Among other compilations of papers on geothermal energy are the proceedings of the second and third All-Union conferences on geothermal energy organized by the Scientific Council for Geothermal

Table 2. Problem areas in the development of the geothermal energy cycle

| |
|---|
| Variability of geothermal resources |
| Location of subsurface reservoirs |
| Reservoir evaluation |
| Extraction technology |
| Conversion technology |
| Potential for multiple utilization |
| Environmental impact control |
| Legal and institutional constraints |

Investigations of the U.S.S.R. Academy of Sciences. Translations of these proceedings are not generally available, but much of the technical content is given in the Soviet papers of volume 2 of the United Nations Symposium and in the ARPA reviews of Soviet literature in geothermal energy. The proceedings of the Second United Nations Symposium held in San Francisco in May 1975 adds another major contribution to the literature of geothermal energy.

## GEOTHERMAL RESOURCES

The upper 10 km of the Earth's crust may contain more than $3 \times 10^{26}$ cal of heat, a resource base readily classified as vast. However, much of this energy is too diffuse to be exploitable as an energy source. Geothermal resources may be defined as localized deposits of geothermal heat concentrated at attainable depths, in adequate volumes, and at temperatures sufficient for commercial exploitation.

The only geothermal resources presently used for electric power generation are high-quality hydrothermal convective systems which contain high-enthalpy geofluids suitable for transferring the geothermal heat to the surface for direct use in low-efficiency steam turbines. Unfortunately such resources have been discovered at only a few places on earth. More than 75 percent of the world's geothermal electric power capacity results from vapor-dominated hydrothermal systems which produce dry or superheated steam for direct conversion. The remaining capacity results from high-temperature, low-salinity, water-dominated hydrothermal systems in which the geofluids are flashed on production, and only the separated steam is used for electric power generation. The liquid fraction is either wasted or reinjected into the ground. These systems are commercially less desirable because only a small fraction of the water flashes to steam, thermal efficiencies are low, and plant operational problems are more severe.

Liquid-dominated hydrothermal systems are expected to be many times more abundant than vapor-dominated hydrothermal systems. Moderate-to-high salinity hydrothermal resources may be more abundant than low-salinity resources. And other types of geothermal resources, such as hypersaline brines, geopressured fluids, volcanic and magmatic deposits, and impermeable hot-rock massives, which are not yet commercially exploitable, may be even more abundant than the currently exploited hydrothermal resources. Thus the answer to the utilization enigma may lie not so much with the magnitude of the resource base, but more with the ability to locate suitable concentrated deposits of geothermal heat and with the technology to extract the energy in quantities which are economically and environmentally feasible.

Although estimates of the geothermal resource base are available, the magnitude of the potential reserves is not yet well defined. The location of underground deposits of geothermal heat, especially where thermal manifestations are not visible at the surface, is a difficult task. Over 1 million acres of "hot spots," areas of known geothermal energy, were identified as early as 1967 by the U.S. Department of the Interior in designated Federal lands in five Western States as having current potential value as geothermal resources. An additional 96 million acres of land in 13 States were designated as prospectively valuable for geothermal resources. Since then several other inventories of known geothermal resource areas (KGRA) have been compiled. A current assessment of U.S. geothermal resources has been completed by the U.S. Geological Survey and a summary of the resource base, by resource type, is given in table 1.

Exploration for geothermal resources has been undertaken by industry on private lands and, through the Federal Leasing Act of 1970, on Federal lands by competitive and noncompetitive leasing under supervision of the Bureau of Land Management. Although total values are difficult to ascertain, it is estimated that about 100,000 acres on Federal public lands and about 200,000 acres on Federal Indian lands were under lease for geothermal exploration in mid-1975.

Resource exploration and assessment of potential reservoirs of geothermal energy are made by the variety of earth science methods listed in table 4. Details of these methods are available in the general references listed in the introduction. The final phase of geothermal exploration is the drilling of exploratory wells. It is from these wells that data for evaluating the suitability of the

Table 3. Summary of geothermal resource base of the United States

| | Estimated heat content ($10^{18}$ cal) | |
|---|---|---|
| | Identified | Potential |
| Hydrothermal convection systems | | |
| Vapor-dominated (steam) | 26 | 50 |
| High temp. - hot water (T > 150° C) | 370 | 1,600 |
| Mod. temp. - hot water (90° - 150° C) | 345 | 1,400 |
| TOTAL | 740 | 3,000 |
| Hot igneous systems | | |
| Magma and hot rock | 25,000 | 100,000 |
| Geopressured basin part of regional conductive systems | 10,920 | 44,000 |
| Total resource base | 36,660 | 147,000 |

[a] From D. E. White and D. L. Williams, eds., *Assessment of Geothermal Resources of the United States - 1975*, U.S. Geological Survey Circular 726, 1975.

resource as a production reservoir are obtained. Major factors in the economics of exploration and production of geothermal fields are the success of techniques available for surface exploration of potential resources and exploratory drilling of potential reservoirs. Improvements and novel methods for reducing costs in these two initial phases of the geothermal energy cycle are thus of great importance. In order to achieve the goal of providing an equivalent of 1 million barrels of oil per day by geothermal resources, it is evident that exploration for geothermal resources, especially hydrothermal, must receive a very high priority by the U.S. energy resource industry.

The magnitude of hydrothermal resources required can be estimated from the following calculation for a 100 MWe generating plant operating with flashed steam of 556 kcal/kg (1,000 Btu/lb) heat content. The required geofluid production rate for a hot-water system yielding 10 percent steam on flashing with a thermal efficiency of 20 percent would be 7.75 x $10^6$ kg/h (1.7 x $10^7$ lb/hr). The amortization of the 100 MWe plant over a period of 30 years would require a total production of 2.1 x $10^{12}$ kg hot water, and a mean reservoir porosity of 10 percent would require a geothermal reservoir volume of about 2 km$^3$. At a 50-percent condensation efficiency, the plant would discharge a hot water supply of about 100,000 m$^3$/d (2.5 x $10^7$ gpd).

For a national capacity of 20,000 MWe, these values are multiplied by a factor of 200. Thus reservoirs supporting 200 units of 100 MWe generating plants must be located. These reservoirs will produce about 1.6 x $10^9$ kg/h of hot water. For a mean well production flow rate of 250,000 kg/h, a total of 6,000 production wells will be needed, and for a mean spacing of 100,000 m$^2$/well (25 acres/well), a total reservoir area of 6 x $10^8$ m$^2$ (1.5 x $10^5$ acres) of geothermal resources must be found. It is evident that if hydrothermal systems are to provide the Nation with 20,000 MWe, very high priority for resource exploration and assessment is indeed required.

## UTILIZATION TECHNOLOGY

Utilization of geothermal energy varies with the quality of available resources. It has been noted that the present geothermal industry has focused on high quality hydrothermal resources. Extraction and conversion technologies for dry-steam reservoirs are sufficiently advanced to be commercially attractive. Conversion technologies for hot-water resources are more complex, and

**Table 4. Geothermal exploration methods**

- Exploration surveys
  - Airborne
    - Aeromagnetic survey
    - Thermal infrared survey
  - Geological
    - Tectonics and stratigraphy
    - Recent faulting
    - Distribution and age of volcanic rocks
    - Thermal manifestations
  - Hydrologic
    - Surface discharge of geofluids
    - Temperature of fluids
    - Chemical composition of fluids
    - Groundwater hydrology
    - Meteorology
  - Geochemical
    - Chloride concentration
    - $SiO_2$ content
    - NA-K-Ca ratios
    - Isotopic composition of hydrogen and oxygen
  - Geophysical
    - Geothermal gradient
    - Heat flow
    - Electrical conductivity
    - Seismic activity
- Exploration hole drilling
  - Reservoir characteristics
    - Temperature-depth profile
    - Pressure-depth profile
    - Lithology and stratigraphy
    - Permeability log
    - Porosity log
    - Fluid composition

for hot brines, geopressured basins, and hot dry rock formations, they are even more complex; commercial utilization is still further away. Since these latter types of resource hold great promise, technology to exploit them must be developed.

Stimulation of geothermal energy production can be achieved by research and development to (1) increase the modes of resource utilization, (2) improve energy conversion technology, and (3) provide advanced methods of energy extraction. Increased efficiency in each of these three aspects of the geothermal energy cycle is attainable.

Development of a geothermal field generally involves the geofluid characteristics, steam separation and gathering facilities, turbine and generator equipment, cooling systems, and condensate disposal methods. Such development presupposes that electric power generation is the sole purpose of the field development. It may turn out, however, that for many geothermal reservoirs, nonelectric utilization of the resource may make the reservoir economically feasible, with significant conservation of fossil and nuclear fuels. Several modes of utilization of geothermal resources are listed in table 5. Hydrothermal fluids with temperature or enthalpy too low for economic electric power production may be useful for water or mineral sources and for industrial, agricultural, and municipal heating. However, since major interest in geothermal energy is for the production of electric power, combined or total utilization may help make many geothermal reservoirs submarginal in power production alone become economically feasible. The possibility of building a community around a geothermal resource, with municipal heating, an industrial park of process firms requiring hot water and concomitant electric power production appears feasible. Thus, research for methods stimulating geothermal resource utilization in all forms is well warranted.

**Table 5. Utilization of geothermal energy**

Electric power production
- Direct use of dry steam
- Flashing of hot water to steam
  - Surface flashing
  - Insitu flashing
- Binary and hybrid cycles
- Innovative single-well converters

Direct use of thermal waters
- Agriculture
- Aquiculture
- Space heating
- Industrial processing
- Medical therapy

Byproducts
- Mineral extraction
- Water resources

General methods for producing electricity from geothermal fluids are summarized in table 6 and are described adequately in the several cited references. The choice of a conversion cycle is generally dependent on the thermodynamic and chemical properties of the geofluid. Present commercial plants utilize low-salinity hydrothermal systems with steam or water at temperatures above about 200° C in the single-stage direct steam turbine conversion system. To utilize lower temperature fluids, investigations are underway to develop other conversion systems; among these are multiple-flash low-pressure steam turbines, single and multiple stage binary cycle systems, and hybrid systems combining these two. The binary system appears to be the most promising for utilization of geofluids with temperatures between 100° C and 200° C. However, only one experimental facility, the Pauzhetka station in the Kamchatka peninsula of the U.S.S.R., has been constructed to date. The binary system most likely to be successful in the United States will require a downhole pump to prevent flashing, a heat exchanger which can operate without excessive corrosion and deposition, and a circulation system which allows for reinjection of the geofluids for environmental control purposes.

Several types of downhole pumps are under development, involving design concepts which use: (1) in situ heat to operate a closed steam-generator turbine to drive the pump, (2) a high-speed, high-temperature, high length-to-diameter electric-motor driven pump, or (3) a hydraulically driven unit with hydraulic power from the surface. Heat exchanger concepts include fluidized sand beds to enhance heat transfer rate and maintain clean surface, and liquid-liquid systems with direct contact of immiscible fluids, tray-tower contactors, or subcritical or supercritical power cycles.

Flash and binary systems are useful in large power plants having capacity in excess of 50 MWe. They require complexes of multiple-well field development and extensive networks of gathering lines. Innovative conversion systems are under development in which small power plants, in sizes of 1 to 15 MWe, may be installed at individual wells. These systems may involve a total flow concept in which both the thermal and kinetic

Table 6. Types of geothermal power plants

| Heat source | Generation mode |
|---|---|
| Dry steam | Steam turbine |
| Hot water (T > 160° C) | Steam turbine |
| Hot water (T < 150° C) | Binary cycle |
| Hot water (moderate salinity) | Hybrid cycle |
| Hot brine (pressurized) | Binary cycle |
| Hot brine (flashed) | Impact turbine<br>Helical screw expander<br>Bladeless turbine |

energy of the geofluid is used for production of electricity.

One of these is the impulse turbine, in which the thermal energy is converted to kinetic energy through a converging-diverging nozzle, and the high-velocity output drives a hydraulic impulse turbine operated at low back pressure. Calculations indicate that a large unit (e.g., 200 MWe) might be feasible for the Salton Sea geothermal brines, which contain as much as 230,000 ppm total dissolved solids. The material handling problems of such brines are indeed enormous, but the dissolved solids may also represent a source of valuable minerals, such as lead, manganese, and copper, if they can be processed economically.

Another total-flow concept is the helical rotary screw expander which expands the vapor from hot saturated liquids by continuous pressure reduction in the expanding screw, in essence creating an infinite series of flashing stages. A small 62.5 kV prototype model was tested successfully with moderate salinity geofluids with indications that it can accept the total flow of untreated brines. Still another concept is the bladeless turbine, in which a series of closely spaced disks are rotated by viscous drag exerted by geofluids introduced by a nozzle. The device seems simple and self-cleaning, but the overall efficiency may be small.

Increased extraction efficiency represents a major means to stimulate geothermal energy production, especially for nonhydrothermal reservoir systems. Calculations show that hot-water reservoirs contain a larger amount of available energy than steam-filled reservoirs under the same reservoir conditions because of the much larger mass of water; but in either system, the heat contained in the rock formation is much larger than the heat in the fluids. Thus recovery of the formation heat would be of major economic significance. Extraction of formation heat must be a nonisothermal process, which can be achieved either by flashing geothermal liquids to steam within the formation or by recycling colder fluids back into the formation. Laboratory investigations and theoretical calculations of reservoir models are underway to determine the extent of heat extraction from fractured reservoir formations.

The natural extraction efficiency of energy from impermeable hot dry rock formations is extremely small. And yet hot dry rock in the upper 10 km of the Earth's crust represents a major potential resource of geothermal energy. The volumetric energy extractable from hot dry rock, calculated for average expected properties and possible technical extraction efficients, is of the order of $1.2 \times 10^9$ kWh/km$^3$ of fractured rock, equivalent to a volumetric power extraction of 1.4 MW/km$^3$ for one century. The technical challenge is the ability to fracture such volumes of hot rock massives and achieve an extraction efficiency of the order of 10 percent.

Fracture stimulation methods are useful for many types of geothermal reservoirs. In vapor-dominated systems, stimulation may restore declining pressure or connect dry holes in commercial steam fields to producing sections. In liquid-dominated systems lacking sufficient productivity for economic power generation, fracture stimulation may provide larger wellbore diameter for increased flow rate, greater surface area for heat transfer, or restore porosity or permeability around wells having deposited silica, calcite, or other precipitated minerals. In dry geothermal systems, stimulation is needed to provide large fracture volumes for heat transfer to an artificial convective extraction system.

Several fracturing methods are under study; these include hydraulic fracturing, thermal stressing, and chemical and nuclear explosive fracturing. Hydraulic and explosive fracturing methods have already proven successful in stimulation of natural gas reservoirs.

Experiments to evaluate the potential for hydraulic and thermal stress fracturing for recovery of geothermal energy from hot dry rock formations are underway. In this concept a large diameter vertical crack is created hydraulically at the bottom of a borehole in the geothermal formation. A second hole is drilled to intersect the upper part of the fracture, and a pump is used to initiate artificial heat-extraction circulation. It is hoped that pumping can be discontinued if a natural convective circulation is achieved. The major technical problems are the attainment of a vertical crack of about 2 km diameter with sufficient fracture area, the creation of additional fracture areas by thermal stress of cold water injection, and the ability to achieve a natural convective circulation without undue losses of water, especially in arid regions. Calculations indicate that under favorable conditions, the system might provide an average power of about 100 MW (thermal) for 20 years.

## INSTITUTIONAL ASPECTS

Although much remains to be done in locating adequate reserves and developing adequate technology to meet the goals for exploiting the Nation's geothermal resources, there is great confidence that these will be achieved. These problems involve advances in physical research and technology. Institutional problems, however, also exist. Such problems are complex; they involve public acceptance, vested interests, historical precedents, existing regulations from other resources, overlapping jurisdictions, and economic and financial factors. These problems are often more difficult to resolve than are engineering problems, and they may in the long run be the major constraints to an accelerated, but orderly development of geothermal resources. The solutions to many institutional problems may require broad public interaction, changes in regulations and legislation, and perhaps changes in traditional investment and marketing procedures.

Economic factors affect all forms of energy supply; they involve total capital costs per installed power unit and operational costs per unit of energy production. For geothermal energy, both of these cost factors are strongly dependent on the specific characteristics of individual reservoirs and the size of the installed power plant units. Important capital costs include the investments for exploration, drilling and completion of wells, gathering lines, and waste-handling systems for all utilizations. For thermal energy applications, they also include the distribution system, and for electric power production, they include the power plants and the transmission network. The production costs are influenced by the cost of capital, operations and maintenance, and plant utilization factor. In the United States, additional costs must also be added for environmental pollution control.

Factual cost data for geothermal electric power production in the United States are available only for the Geysers field. The electric utility purchases steam from only one supplier, but has negotiated to purchase steam for future plants from additional suppliers. In the development of future geothermal power stations, an option exists for an integrated operation from exploration to power production in contrast to the traditional roles of an electric utility purchasing steam or hot water from an independent supplier. The general effect would be an increased investment cost per kilowatt hour of energy.

Data for costs of recently constructed power plant units at the Geysers are sparse, but estimates for the original plants range from about $100 to $150 per kW. Production costs were estimated at about 7 mill/kWh of which about 3.5 mill/kWh was the price of the purchased steam. These estimates included a cost of 0.5 mill/kWh for injection of water condensate as a disposal method. With escalation of drilling, construction, and environmental reporting costs over the past few years, these cost values are not useful for estimating costs of new facilities, especially for reservoirs which do not produce dry steam. Recent estimates indicate installation costs may range from $600 to $700 per kW and operating costs for binary conversion systems of the order of 30 to 40 mill/kWh. These costs, of course, are hypothetical, and more precise costs will be generated as other major reservoirs and plants are developed and operated. A large uncertainty in the total cost is the fixed exploration cost for the resource, which is independent of plant capacity, and the average drilling costs of the production, dry, and injection wells. Computer models to evaluate the relative importance of these resource and utilization costs are under development.

Because of large uncertainties in the technical costs of exploration and drilling, conversion efficients, and stimulation techniques, and because of the rapid escalation rate of these costs, it is difficult not only to estimate costs on an absolute basis, but even to compare costs of other forms of electric power generation.

Besides the costs affected by these technical factors, other factors more social in nature must be considered. Among these are public acceptance and government stimulus for accelerating the development of geothermal energy in relation to other energy sources, the interpretation of compliance with the National Environmental Protection Act of 1969, and the availability of investment capital for development of geothermal resources and electric and thermal power plants. These socioeconomic factors may require much public and government deliberation before general philosophies are widely accepted in practice.

Although geothermal energy is considered to be one of the least polluting of the many forms of energy available, it should be assumed that the public will insist that the environmental impact of producing geothermal energy in all of its natural and stimulated forms be thoroughly investigated in accordance with NEPA and any additional requirements under State and local legislation. Furthermore, in addition to environmental impact, it is also evident that assessment will be required of the operational aspects of the various types of resources which affect personnel safety and plant maintenance.

In the evaluation of a benefit-risk analysis, geothermal energy is expected to compare favorably with respect to other energy resources, especially when viewed over the entire fuel cycle. Since geothermal energy must be utilized or converted in the vicinity of the resource, the entire "fuel cycle" from reservoir to transmission is located at one site. This is in contrast with material fuels in which the cycle involves mining, storage, refining, transportation, reprocessing, and waste disposal, many or all of these at different locations. Furthermore, increased utilization of geothermal energy may result in a correspondingly reduced demand for material fuels in short supply, such as natural gas, oil, coal, and uranium. And still further, geothermal fluids may provide byproduct sources of water with reduced demand for cooling water.

Geothermal energy, nevertheless, has its array of potentially deleterious environmental impacts. A list of potential environmental impacts is given in table 7. A review of the more important ones has recently been completed in a workshop sponsored by the National Science Foundation (ref. 7) as the basis for a program to support research for baseline data and technology for monitoring potential impacts and controlling actual

Table 7. Environmental impacts of geothermal power production

| Land | Water | Air |
|---|---|---|
| Land utilization<br>~2 km$^2$/100 MW | Disposal of drilling fluids | Release of steam and other gases during drilling and testing |
| Drilling operations<br>~10 wells/km$^2$ | Need for supplementary cooling water | Noise pollution |
| Power plant construction<br>1 plant/100 MW | Buildup of salt concentrations | Release of $H_2S$ and other noncondensable gases |
| Steam gathering lines<br>~0.2 km/100 MW | Disposal of condensor cooling water<br>steam condensate<br>~3.5 Mgpd/100 MW | Potential changes in micrometeorology |
| Condensate reinjection lines and pumps | Potential mineral and thermal pollution of fresh surface waters | Potential for well blowout |
| Potential for<br>Land subsidence<br>Seismic activity | | |

hazards. The major impacts include gaseous emissions, liquid waste disposal, and geophysical effects such as seismicity and subsidence. Other concerns involve thermal releases, surface water contamination, land use planning, cooling water consumption, and visual and noise pollution.

An array of legal problems associated with geothermal resource development also exists. These have been reviewed in another workshop sponsored by the National Science Foundation (ref. 8).

The legal problems of geothermal resources begin with resource definition, which varies from State to State. For example, in California geothermal resources are defined as "the natural heat of the earth, the energy—which may be extracted from naturally heated fluids—but excluding oil, hydrocarbon gas or other hydrocarbon substances." This definition leaves open the question whether geothermal resources are legally defined as water, mineral, or gas resources, and results in large uncertainty with respect to Federal, State, and local jurisdictions. On the other hand, the State of Hawaii considers geothermal resources as minerals, whereas the State of Wyoming has declared them water resources. As water resources, they would be subject to the very complicated set of State laws concerning water rights and regulation. As minerals, they would be subject to mining laws and such problems as ownership, depletion allowances, and write-off of intangible drilling costs. Geothermal resources have already been classified in court decisions in different ways. In one case a U.S. District Court in San Francisco treated the Geysers geothermal resource as "nothing more than superheated water" and therefore not a mineral, but in another case, the resource was held to be a gas within the meaning of the Internal Revenue Code provisions for depletion allowance and intangible drilling costs.

Ownership rights are also a serious institutional problem. The Federal Government has given some 90 million acres of land to the homesteaders, States, and railroads, but generally reserved the mineral rights to the Federal Government. However some State grants included mineral rights and thus many problems exist in the ownership aspects of Federal and State lands under the leasing of these lands for geothermal energy development. Land utilization for geothermal resources also comes under the jurisdiction of local governments, except for resources on State or Federal lands.

Other institutional questions at the State level include the acreage level for commercial development, the need for long-range financial and land use planning, and the overlapping of State regulatory agencies with each other and with jurisdictions of local governments for permits, licenses, taxation, and especially environmental control. The latter may be effected at the Federal, State, regional, county, or city government levels. For example, in some areas, authority may be divided between such agencies as a Regional Land Development Commission and a County Air Pollution Control Board.

The institutional aspects of licensing and regulation of power plants is very complicated; they cover the spectrum from Federal to local jurisdictions. Regulations already exist with respect to the exploration, drilling, and operation of water and mineral wells in all States. The extension to geothermal wells should be relatively simple. Yet the need to satisfy the provisions of NEPA and any specific State environmental requirements may make geothermal resource development a slow process. For example, in California, the State Lands Commission, before it can lease any lands under its jurisdictions, must make a finding at a public meeting that the lease will not have significant detrimental environmental effect and must prepare an environmental impact report available to the legislature and the public. The corresponding problems of environmental impact from geothermal resources in private lands are not yet fully resolved.

Once the field is developed to the point where a utility contracts to purchase the resource and construct a power plant, other regulatory agencies come into the picture, such as the Federal Power Commission and corresponding State and local agencies. Site selection and environmental analysis criteria are becoming of major importance in power plant licensing for all types of energy resources and their effect on geothermal energy development will probably be determined by solution of these problems on a generic basis, rather than specifically for geothermal energy alone.

Institutional problems thus involve many social, legal, environmental, and economic questions. The problems become more complex for land use planning when geothermal resources span Federal, State, and private lands. They involve capital investment problems for geothermal development which may be considered to be high-risk and involve long-delay times until they become income producing. They involve interindustry arrangements when multiutilization or total utilization is needed to support economic development of electric power generation, thermal power heating, desalination and mineral recovery. And they involve multigovernment arrangements in the realms of regulation, licensing, and environmental control.

## NATIONAL GEOTHERMAL PROGRAM

Although significant growth of the one natural steam field in the United States has occurred since 1960, it has become apparent that a major national effort of industrial development supported by Federal stimulation is needed to develop the potential of geothermal resources in its several forms as an alternate energy source. Early efforts to achieve a coordinated Federal program for the support of research and development were undertaken by an informal Interagency Panel for Geothermal Energy Research. From these efforts evolved a 5-year program whose objective was the rapid development of a viable geothermal industry for the utilization of geothermal resources for electric power production and other products. The goals and plans for this program were prepared by the Interagency Task Force on Geothermal Energy under direction of the National Science Foundation in the Federal Energy Administration "Project Independence Blueprint" (ref. 9). The task force evaluated two alternate strategies. The first was "business-as-usual," which assumed continuation of current policies affecting levels of geothermal production. The second was "accelerated demand," which assumed specific changes that would result in a more rapid expansion of potential production.

The task force estimated that under the "business-as-usual" assumptions, electric power capacity could reach 4,000 MWe by 1985 and perhaps 60,000 MWe by 1990. The corresponding numbers for the "accelerated demand" assumptions were 20,000 to 30,000 MWe by 1985 and 100,000 MWe by 1990. These latter values were adopted as the primary goal of a proposed National Geothermal Energy Research Program, which was directed toward (1) providing the necessary technological advances to improve the economics of geothermal power production, (2) expanding the knowledge of recoverable resources of geothermal energy, and (3) providing carefully researched policy options to assist in resolving environmental, legal, and institutional problems.

The major research funding agencies which contributed to the task force program were the Atomic Energy Commission, the Department of the Interior, and the National Science foundation which served as lead Federal Agency. The status of the research carried out under support from these agencies is described in the proceedings of a conference on research for the development of geothermal energy resources (ref. 10).

During 1974, two acts of Congress resulted in a marked change in direction for the national development of geothermal energy. The first was PL 93-410, the Geothermal Energy Research, Development, and Demonstration Act of 1974, which established a Geothermal Energy Coordination and Management Project. The Project was given responsibility for the management and coordination of a national geothermal development program which included efforts to: (1) determine and evaluate the geothermal resources of the United States; (2) support the necessary research and development for exploration, extraction, and utilization technologies; (3) provide demonstration of appropriate technologies; and (4) organize and implement the loan guarantee program authorized in Title II of the Act.

The second law was PL 93-438, the Energy Reorganization Act of 1974, which established the Energy Research and Development Administration, ERDA, with responsibility as lead Federal agency for activities related to R&D of all energy sources. The Act abolished the AEC and transferred the geothermal development function of the AEC and NSF to ERDA. On January 19, 1975, ERDA assumed responsibility for the national program of geothermal energy development. It has also assumed direction of the Geothermal Energy Coordination and Management Project, which has completed the Final Report required by PL 93-410 (ref. 11). In addition, ERDA, in response to Congressional requirements and internal needs, prepared a comprehensive R,D&D plan (ref. 12) for developing energy technology options. The geothermal section of the plan built upon the predecessor plans of the Task Force for Geothermal Energy and the Geothermal Project and has based the goal for the national program on the rational given in volume 2 of the Plan.

The objectives being considered in the ERDA program for geothermal energy include methods to stimulate the industrial development of indigenous hydrothermal resources to provide the Nation with 10,000 to 15,000 MW of electric power and thermal energy during the 1985 to 1990 period and to develop new and improved technologies for cost-effective and environmentally acceptable utilization of all types of geothermal resources as a long-term alternate source of energy.

The strategy of the program which might accomplish such objectives would be to accelerate industrial development of the Nation's geothermal resources by (1) coordinating efforts for exploration and assessment of geothermal resources necessary to establish reserves by 1978-1980 which can support production of 20,000 to 30,000 MW of power, (2) demonstrating near-term and advanced technologies needed to utilize many types of geothermal resources in a cost-effective and environmentally acceptable manner, and (3) fostering rapid development of a viable geothermal industry by appropriate incentives, timely reduction of institutional impediments, and direct participation of the private sector in development and demonstration of geothermal energy technology.

Although ERDA assumes overall responsibility for effective management and coordination of Federal geothermal activities, the scope of the Federal program includes the efforts of many Federal agencies. The Geothermal Steam Act of 1970 authorized the Department of the Interior to lease Federal lands for geothermal resource exploration, development, and production of energy and useful byproducts (such as methane, desalinated water, and valuable minerals). The leasing program is conducted by the Bureau of Land Management, which is responsible for selecting lands for lease and holding lease sales, and the U.S. Geological Survey, which classifies the lands by appraised value.

The U.S. Geological Survey's geothermal research program is focused on the characterization and description of the nature and extent of the geothermal resources of the United States. The output of the U.S. Geological Survey's program is the determination of the magnitude of the geothermal resource base on a national and regional basis. The Survey's program includes development of exploration technology, methodology for estimating energy potential of geothermal systems, environmental effects of geofluid withdrawal, and geochemical aspects of reservoir permeability.

Some of the problems that have retarded the delineation of the Nation's geothermal resources through the leasing of public lands include the lack of reliable information regarding suitable resources, even on lands classified as KGRA's, insufficient requirements for early exploration and development of leased lands, and legal problems involving ownership and control of use of geothermal resources. Under a national program, coordinated effort by ERDA and the Department of the Interior would help to accelerate the establishment of geothermal reserves by the resource industries. Potential actions include (1) accelerated estimation by the U.S. Geological Survey of the available resources by geologic type, (2) improved technology for resource exploration and assessment and for reservoir evaluation, (3) easing of leasing impediments by better methods for designating KGRA's and establishing minimum acceptable bids, (4) incentives for early development of leased lands, and (5) recommendations for legislation to resolve legal uncertainties pertaining to geothermal resources.

The second part of the strategy for the Federal program would center on ERDA efforts for demonstration of near-term and advanced systems for resource utilization, development of supporting research and technology, and execution of the Federal loan guarantee program. Demonstrations of utilization technology could occur as (1) commercial-scale demonstration plants to provide the public sector with operational experience with full-scale electric power plants capable of generating energy at design production cost under pertinent environmental and institutional conditions, (2) pilot-plant facilities to prove technical feasibility, provide preliminary economic data, and provide capability for testing new and improved extraction and conversion systems for electric power production, and (3) field test facilities to improve reservoir assessment technology, evaluate reservoir characteristics and performance, test and evaluate energy extraction and conversion components and processes, evaluate material compatibility with geothermal fluids, and test environmental control technologies. A supporting research and development program could provide for development of hardware systems, components, processes, and control techniques for installation in the demonstration facilities and field testing of reservoir evaluation technologies for the range of resource types. Supporting research and development programs could also provide advanced research and technology to the geothermal industry and its supplier and support industries for improved productivity and utilization.

Implementation of the Loan Guarantee program should be coordinated with the Bureau of Land Management's geothermal leasing program and ERDA's research, development, and demonstration program. The program could involve venture capital companies, reservoir developers, and lease holders to maximize the impact of the loan program in stimulating early development of commercial electric and thermal power facilities. The Loan Guarantee program might be used primarily for income-producing projects, such as field development and powerplant construction. Smaller industrial firms could benefit from guaranteed loans by gaining access to necessary private capital. Regulations and procedures governing the implementation of the loan guarantee program are currently being drafted in coordination with other Federal agencies, such as the Small Business Administration and the Economic Development Administration. Approved regulations and operating procedures setting forth specific information requirements to be met by the applicant and criteria governing the approval process should be widely publicized as early as possible.

The third part of the strategy of the Federal program would involve several Federal agencies, notably the National Science Foundation, involved in assessing environmental, legal, and institutional problems of advanced energy technology under its RANN program, the Environmental Protection Agency, involved in environmental emission standards, monitoring, and control technologies, and the Federal Energy Administration, involved in institutional aspects of the national energy situation.

With the mutual efforts of the Federal program and the geothermal industry, the attainment of the National electric and thermal energy goals for geothermal resources could add a significant alternate energy source to the national economy before the end of the present century.

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# CONSERVATION AND ENVIRONMENTAL IMPLICATIONS OF OPEN-CYCLE MHD*

Finn A. Hals†

## *Abstract*

*It is widely recognized that the development of MHD power generation would enable a much more effective utilization of our fuel resources, in particular, our vast coal reserves with drastic reductions in pollution of air and water. It would serve the following important national goals:*

1. *More effective coal utilization,*
2. *Conservation of all types of fuels,*
3. *Reduced pollution of air and water,*
4. *Significant economic savings, and*
5. *Improved reliability of electric utility power systems.*

*The important potential advantages of MHD relative to existing technology are possible because of the inherent characteristics of the MHD process. This paper discusses how the important goals can be reached and served by MHD, the status of MHD technology today, and its future prospects. The discussion centers on coal-burning, open-cycle MHD central station power generation. The conclusion reached is that the development of MHD can contribute significantly to solving the serious conservation and environmental problems associated with electrical power generation.*

## INTRODUCTION

MHD power generation is now widely recognized as a promising new method for large-scale electrical power generation. It promises a substantial improvement in the thermal efficiency of power plants. This will enable a much more effective utilization of the fuel burned. Furthermore, the MHD power generator can use all types of coal (as well as other types of fossil fuels) with their inherent ash and sulfur impurities and still drastically reduce pollution of air and water. It will allow the burning of coal directly without preprocessing and assure strict emission control of all pollutants. This will make power generation much more compatible with the environment. MHD also promises significant economic gains and improved reliability of electric utility power systems and networks. In summary, the development of MHD power generation can greatly contribute to solving the serious conservation and environmental problems associated with electrical power generation.

This paper will discuss how the above important goals can be reached and served by MHD, the status of MHD technology today, and its future prospects. The discussion here will be limited to open-cycle MHD power generation which by far has met with the greatest attention and largest development efforts both in this country and abroad. It will naturally center on coal-burning MHD power generation since coal represents our largest and most important fossil fuel resource.

Since the advantages of the MHD energy conversion process follows from its inherent characteristics, it is important to understand the principles of the MHD process. Therefore, a brief review of this is first presented before the potential application of MHD to practical electric utility utilization is described along with its conservation and environmental implications. This is followed by a brief review of the status of MHD technology and its further necessary development.

## MHD PRINCIPLE

The principle of MHD is old and based on Faraday's well-known laws of electromagnetic induction. The magnetohydrodynamic (MHD) generator is a heat engine which transforms the heat energy of a gas into electric power in much the same way as a turbogenerator. Thus, the basic physical phenomena employed are the same in both cases. However, there are important fundamental features which distinguish the MHD power generator from conventional electrical power machinery.

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Contrary to a turbogenerator, the MHD generator extracts electric energy directly from a hot gas without the intervention of moving parts. The basic conversion process is a volume process where the gas itself is made to conduct electricity and passes at high velocity through a magnetic field generating electricity. Of greatest importance is that this inherent simple direct process makes it possible to handle high-temperature combustion gases from direct burning of coal and other fossil fuels containing ash and sulfur impurities.

The basic d.c. combustion generator is schematically illustrated on figure 1. Hot combustion gases are produced by burning of the fuel under high pressure and temperature. A small amount of an alkali salt, called seed, is added to the gas to enhance the electrical conductivity of the gas. The hot gases expand at high velocities through the MHD generator channel or duct inserted in a strong magnetic field produced by a superconducting magnet surrounding the duct. This induces an EMF in the gas which drives a current through the gas and external load, which is connected to electrodes inserted in opposite walls of the duct. This type is the basic linear Faraday-type generator. Other generator types with different electrical load connections and of different geometry are also possible.

From a practical engineering point of view, it is important to recognize that the walls of the MHD generator channel assembly as well as the upstream high-temperature burner are cooled by a coolant such as water. The reason for this cooling is the same as that for cooling a combustion engine which operates at the same high peak gas temperatures as the MHD generator. In this way, the operating temperatures of the wall materials are controlled so that ordinary construction materials can be used. Thus, the high gas temperature does not represent a materials temperature limitation for the MHD generator. In fact, any temperature limitation is rather imposed by the theoretical flame temperature which can be reached in combustion of the fuel.

The characteristics of the MHD power generator which make it so well suited for applications to electric utility power generation can be summarized as:

1. the ability to handle high temperatures,
2. the ability to handle very high power levels,
3. no moving parts or close tolerance, and
4. the ability to start and reach full power practically instantaneously.

Because of these important characteristics, the MHD generator has great potential for electric utility power generation applications.

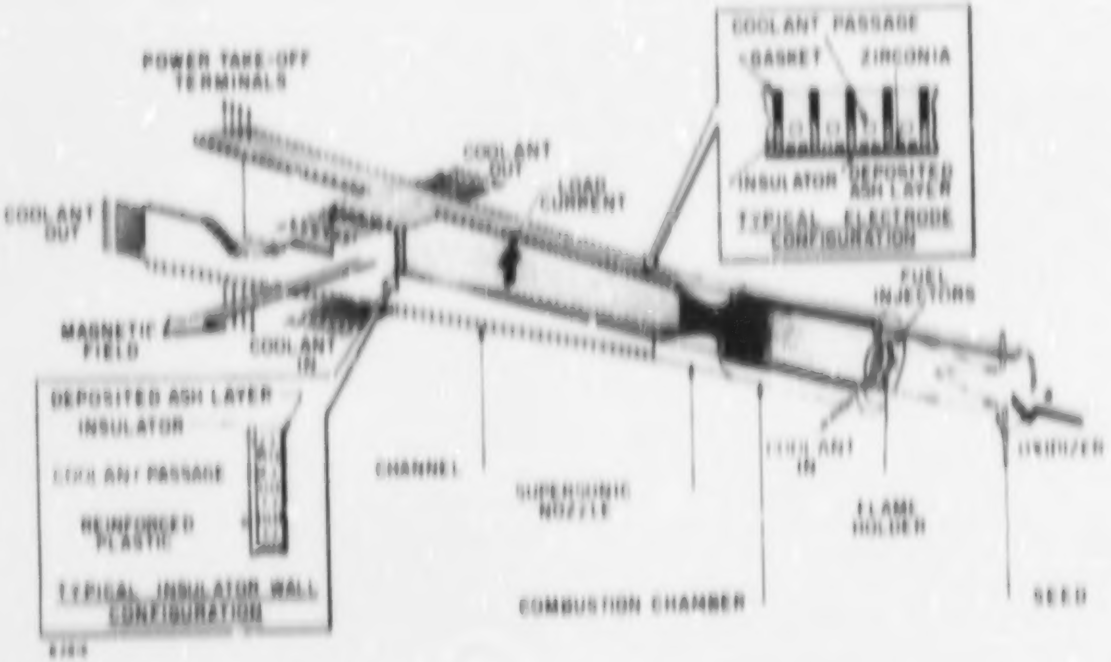

COOLANT PASSAGE
GASKET
ZIRCONIA
INSULATOR
DEPOSITED ASH LAYER
TYPICAL ELECTRODE CONFIGURATION
POWER TAKE-OFF TERMINALS
COOLANT OUT
LOAD CURRENT
COOLANT OUT
FUEL INJECTORS
MAGNETIC FIELD
COOLANT IN
DEPOSITED ASH LAYER
INSULATOR
COOLANT PASSAGE
REINFORCED PLASTIC
TYPICAL INSULATOR WALL CONFIGURATION
CHANNEL
SUPERSONIC NOZZLE
COOLANT IN
OXIDIZER
FLAME HOLDER
COMBUSTION CHAMBER
SEED

Figure 1. Basic d.c. combustion MHD generator.

## APPLICATION TO ELECTRIC UTILITY POWER GENERATION

### *General*

As a heat engine, the MHD generator utilizes a thermodynamic cycle similar to that of a turbine. The intrinsic feature of the high-temperature MHD process for attaining very high cycle efficiencies provided from the early stages in MHD development provided the impetus for development of coal-burning central station baseload power plants. This application has always been considered the major objective of the development of MHD. Therefore, the discussion here will center on this type of application. However, other types of applications such as intermediate load, peaking, or reserve power also represent important potential applications of MHD power generation for electric utility service.

Two basic MHD power plant designs are shown on figures 2 and 3. A binary power cycle is utilized in both designs where coal is burned directly with preheated air and the power is extracted from the hot seeded combustion gases in the MHD generator. The heat in the MHD generator exhaust gas is utilized for regeneration and for production of supplemental power in either a bottoming steam or a gas turbine plant. The important feature of the latter combination is that there is no need for cooling water for condensation of steam. The significance of this plant design feature will be reviewed in more detail later together with the important gas cleaning and air pollution control aspects of MHD power plant designs. However, it should be noted at this point that the gas turbine in a combined MHD power cycle operates with *air* instead of combustion gases as the working fluid, which avoids turbine erosion and corrosion problems from use of combustion gases as working fluid directly.

Another alternate MHD power plant design which recently has received attention is to combine MHD power generation with coal gasification. The MHD generator offers a unique opportunity in this respect because the heat content of the MHD generator exhaust gas can be utilized in the gasification process avoiding fuel efficiency losses otherwise generally associated with coal gasification in connection with power generation.

### *Plant Efficiency, Fuel Conservation, and Heat Rejection*

It is widely recognized that substantially higher power plant efficiencies are attainable with MHD as compared to conventional power technology. Reported results from several power plant efficiency studies and investigations are summarized in figure 4 (refs. 1, 16, 17). Important parameters for determining the efficiency of the power cycle are the preheat temperature which can be obtained of the combustion air and the magnetic field strength which can be employed, since both of these two parameters, particularly the preheat temperature, determine the amount of enthalpy or fraction of fuel energy which can be extracted from the MHD generator.

The conclusion has been reached that early MHD power plants based upon present status and knowledge would attain roughly 50 percent efficiency and that at least 60 percent efficiency could be expected from further development. This means that developed MHD power plants would generate 50 percent more electricity from the same amount of fuel burned as compared to today's most efficient power plants. Thus, MHD would enable power plants to utilize and to conserve our coal reserves and other fossil fuel resources more effectively.

All power plants must reject heat, but the amount of heat rejected decreases rapidly with increasing plant efficiency. This is so because the fraction of the input fuel heat energy which is converted into electricity is just the efficiency, $\eta$, whereas the fraction of heat energy rejected to the environment equals $(1 - \eta)$. Thus, the total amount of heat rejected per unit of electricity produced (3) is $Q = 1 - \eta/\eta$. This relationship is shown by the curve plotted in figure 5.

Comparative data on heat rejection from different thermal power plants are listed in table 1.

The heat rejection is divided into two parts. The first part is specified as the amount of heat rejected to cooling water for condensation of steam and the second as the amount of heat rejected directly to the atmosphere.

In the case where the MHD generator is combined with a gas turbine bottoming plant, there is *no* need for cooling water for condensation of steam and, thermal pollution of water is eliminated. In addition, it should be recognized that a large fraction of the waste heat in this case is rejected at relatively high temperatures (400° to 800° F) in the form of hot combustion gases and hot air exhausting from the gas turbines. Thus, the high-temperature MHD process which extracts energy from the gas at temperatures between 3,000° and 5,000° F permits heat rejection at higher temperatures than other thermal power plants while still maintaining very high plant efficiency. This offers better prospects for utilization of waste heat, such as for generation of low-pressure process steam, for heating purposes, for desalination, etc.

### *Air Pollution Control*

Another pressing pollution problem facing coal burning power plants today is emission control of air pollutants formed during combustion of the fuel. This important item has received particular attention in the

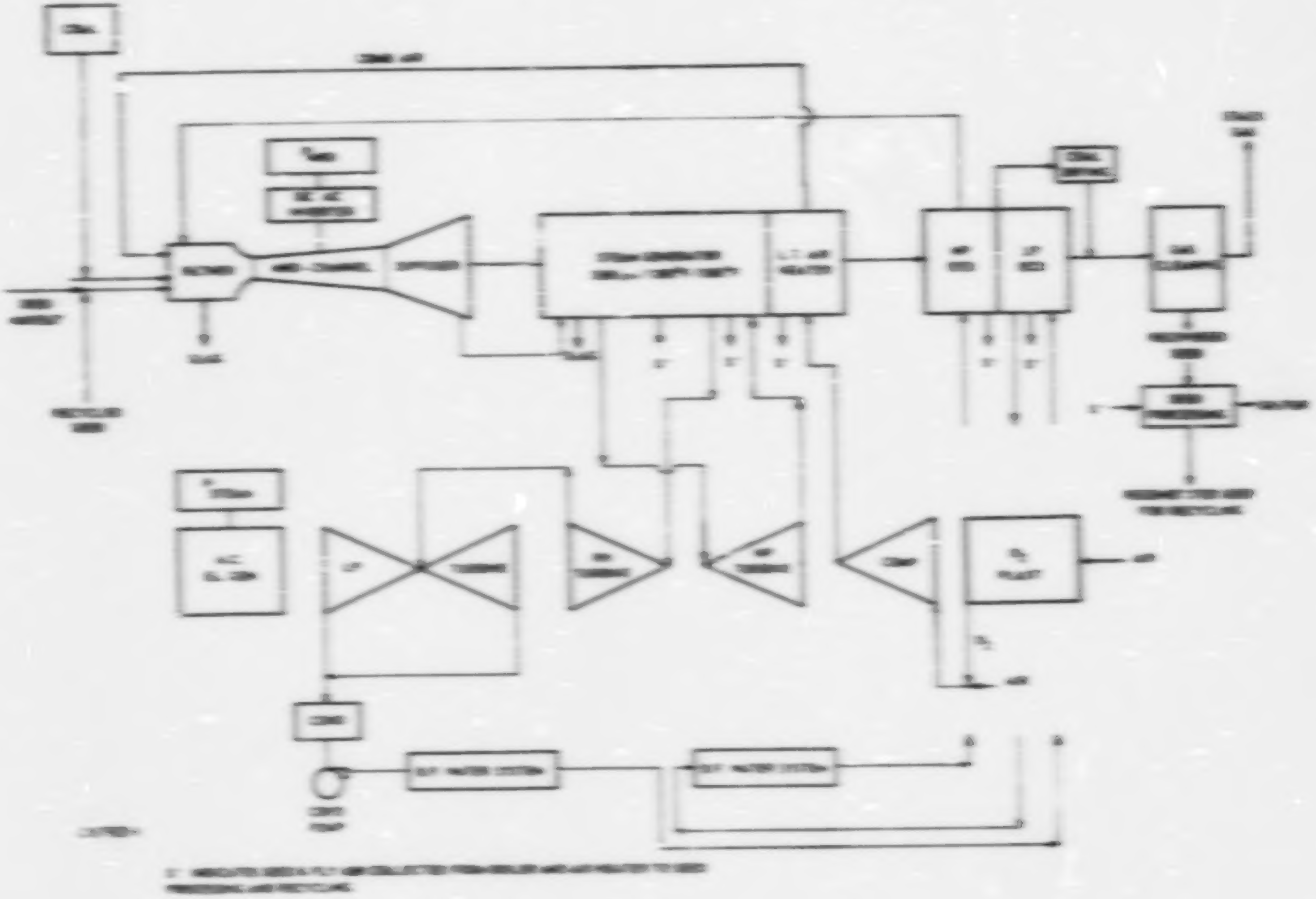


Figure 2. MHD – steam power cycle.

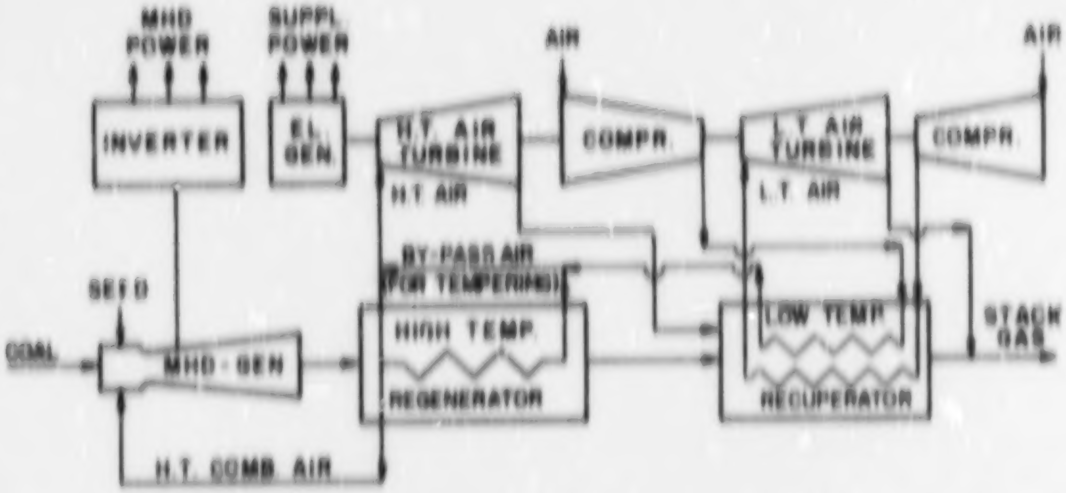


Figure 3. MHD — air turbine power cycle.

development of MHD combustion systems and will be reviewed here in more detail.

The MHD combustion systems have two distinct features which are different from conventional systems. First, the combustion occurs at much higher temperatures, and secondly, a small amount of an alkali seed is added to the combustion gases to enhance the electrical conductivity of the gas. This latter feature necessitates recovery of the major portion of the seed added for economic operation. Therefore, highly efficient gas cleaning equipment for recovery of seed is a natural and integral part of the power plant system. Experimental work has demonstrated that seed together with any particulate matter in the gas can be removed at efficiencies as high as 99.9+ percent by conventional electrostatic precipitators, bag filters, or scrubbers. Furthermore, the alkali seed has a high chemical affinity to sulfur and it has experimentally been verified that the alkali seed will combine with sulfur from the fuel so that sulfur can be effectively removed from the gas together with the seed (refs. 2,3,4). This sulfur removal process requires processing of the recovered seed together with recycling of processed seed and it produces elemental sulfur as a valuable byproduct (ref. 3). The method developed for processing of the recovered seed with sulfur removal is schematically shown in figure 6. In the particular process shown on this figure, $K_2SO_4$ together with any remaining flyash removed from the gas is treated with reducing agents such as carbon monoxide and hydrogen in order to reduce $K_2SO_4$ to $K_2S$. $K_2SO_4$ is formed in the gas under oxidizing MHD generator exhaust gas conditions which have been assumed in this case. However, the possibility exists for operating with slightly fuel-rich conditions at the higher exhaust gas temperatures which will promote the formation of $K_2S$ in the gas instead of $K_2SO_4$. With this mode of operation, $K_2S$ can be directly removed from the gas which eliminates the need for reducing $K_2SO_4$ to $K_2S$ as shown in figure 6. Complete oxidation of the combustion gas is in this alternate mode of operation performed at lower gas temperatures. In any event, the reducing agents necessary for any reduction of $K_2SO_4$ can readily be produced directly from coal by partial oxidation. Coal itself may also be used directly as a reducing agent. $K_2S$ produced in the first reduction step or alternatively removed directly from the gas is then reacted with water vapor and carbon dioxide to form potassium carbonate ($K_2CO_3$) and hydrogen sulfide ($H_2S$). The hydrogen sulfide produced is fed to a conventional Claus plant where elemental sulfur is produced as a byproduct. The $K_2CO_3$ from the process is recycled to the MHD burner.

Since MHD is a high-temperature combustion process, particular attention has been directed towards the control of nitrogen oxides formed at the high combustion temperatures.

There are principally two routes available for control of nitrogen oxides emission (ref. 5). One route is to minimize the nitrogen oxides in the gas so that it is acceptable for direct emission to the atmosphere. The other is to maximize the oxides of nitrogen in the gas so

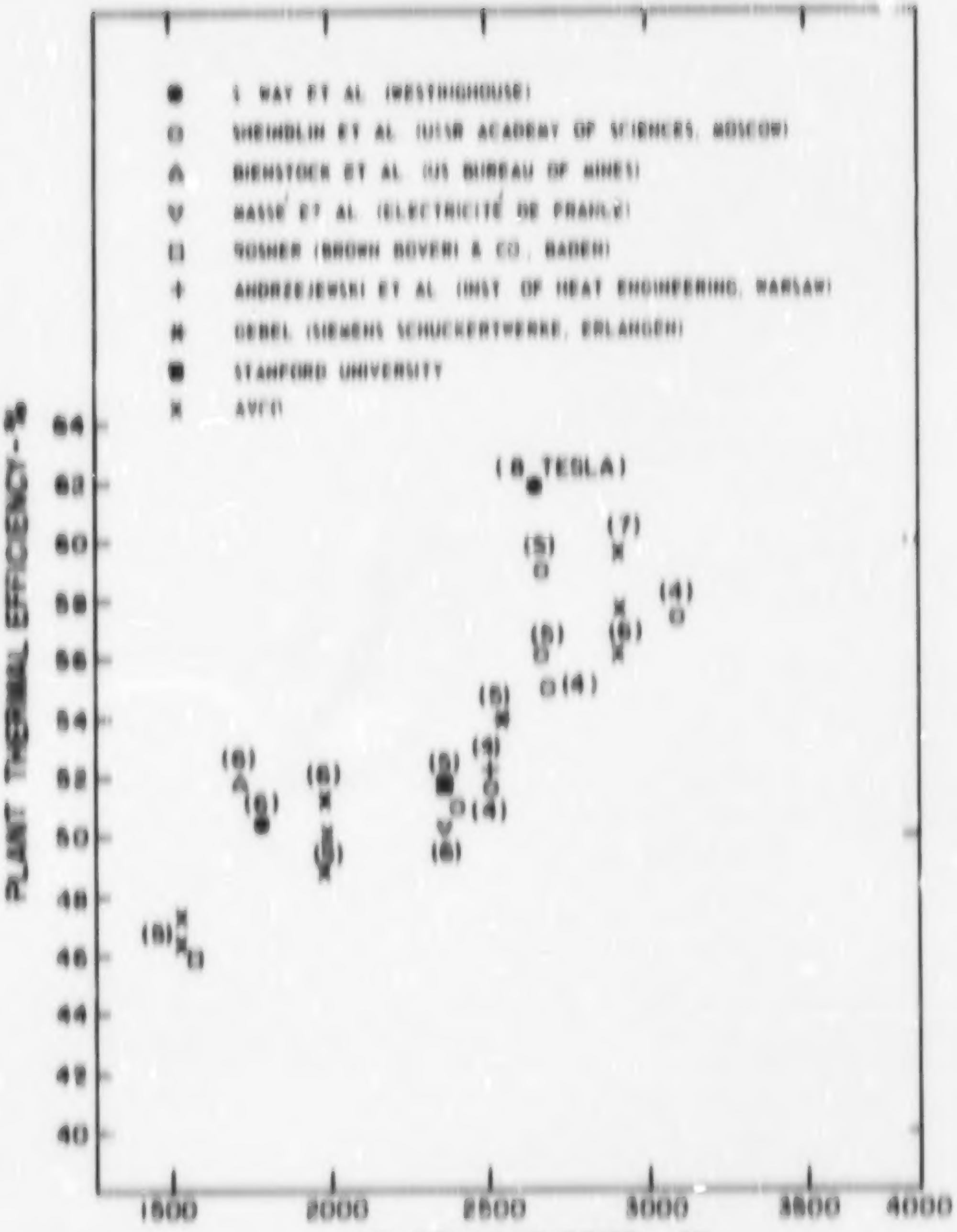


Figure 4. Baseload combined MHD power cycle efficiency.

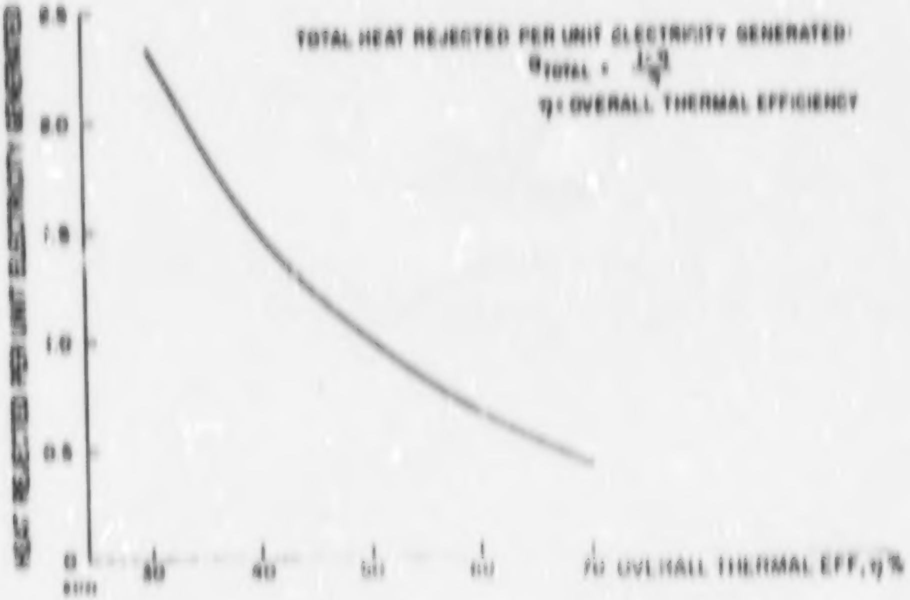
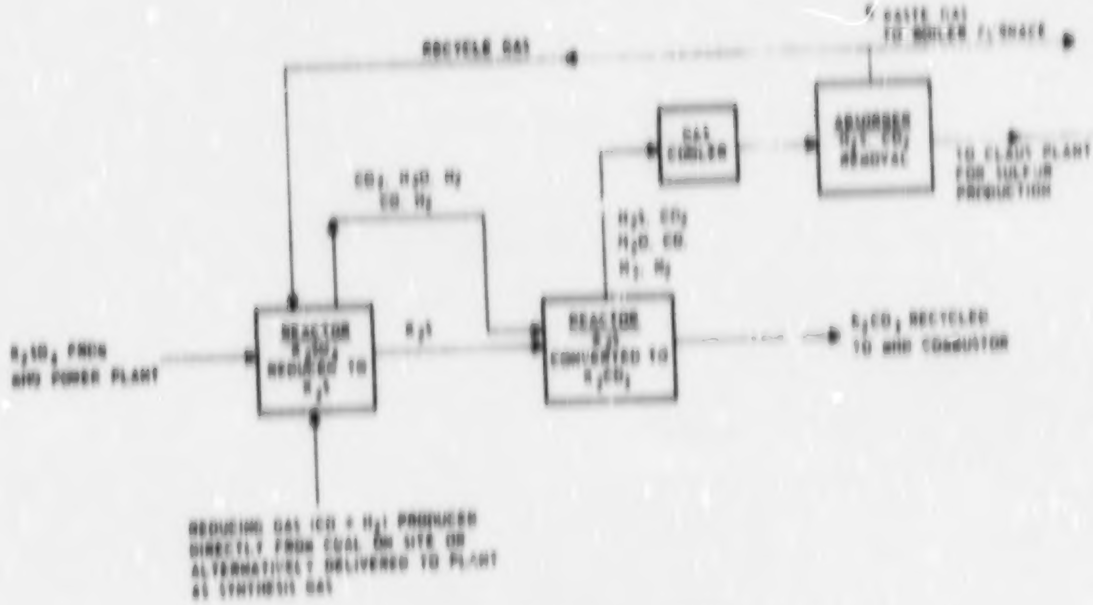


Figure 5. Heat rejection – efficiency relationship for thermal power plants.

Table 1. Comparison of heat rejection from different thermal power plants

(heat rejected per kWh generated)

| Plant type | Thermal eff. (percent) | Condenser (kWh) | Stack gas (kWh) | Total kWh |
|---|---|---|---|---|
| Fossil-steam | 40 | 1.25 | 0.25 | 1.50 |
| Nuclear-steam (Present-advanced) | 32-42 | 2.12-1.14 | 0 | 2.12-1.14 |
| MHD-steam | 50-60 | 0.64-0.50 | 0.18-0.17 | 0.82-0.67 |
| MHD-air turbine | 50-60 | 0 | 0.82-0.67 | 0.82-0.67 |


RECYCLE GAS
* WASTE GAS TO BOILER FURNACE
GAS COOLER
ABSORBER ($H_2S$, $CO_2$) REMOVAL
TO CLAUS PLANT FOR SULFUR PRODUCTION
$CO_2$, $H_2O$, $N_2$ TO $H_2$
$H_2S$, $CO_2$ $H_2O$, CO, $N_2$, $H_2$
REACTOR $K_2SO_4$ REDUCED TO $K_2S$
$K_2S$
REACTOR $K_2S$ CONVERTED TO $K_2CO_3$
$K_2CO_3$ RECYCLED TO MHD COMBUSTOR
$K_2SO_4$ FROM MHD POWER PLANT
REDUCING GAS (CO + $H_2$) PRODUCED DIRECTLY FROM COAL ON SITE OR ALTERNATIVELY DELIVERED TO PLANT AS SYNTHESIS GAS

* WITHOUT $N_2$ IN SYNTHESIS GAS ALL GAS EXITING FROM ABSORBER IS RECYCLED

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Figure 6. Seed recovery process with sulfur removal.

that recovery of fixed nitrogen becomes economically attractive. The main attention has so far in the development work been directed towards the first route with the use of direct reduction as an emission control technique for nitrogen oxides in the gas.

In order to attain a very low emission level of nitrogen oxides by this first route, a two-stage combustion technique with afterburning in the MHD generator exhaust gas is employed. This control technique has been proposed by several investigators in the MHD field and its practical application has been experimentally demonstrated and verified in analytical studies (refs. 6,7,8,9,10,11). These studies indicate that it is possible with this technique solely through direct homogeneous gas reactions occurring in the gas to reduce the level of nitrogen oxides in the stack gas to 100-150 ppm for coal-burning plants or to about 25 percent of the recently adopted Environmental Protection Agency emission rate limitations for such plants. The kinetic history of nitric oxide throughout the power plant system, when two-stage combustion technique is employed, is illustrated on figure 7. Additional reduction through catalytic effects from refractory materials employed in high-temperature air heaters have been reported (refs. 6,11,12,13). This will make it possible to lower $NO_x$ concentrations in the effluent gas further, and to less than 50 ppm which is less than one-tenth of present EPA standards. Emission control of nitrogen oxides through two-stage combustion and direct reduction is presently considered the basic emission control technique for nitrogen oxides from MHD power plants.

Another alternate control technique based upon fixation of the maximum amount of nitric oxide formed in the high-temperature MHD combustion process for recovery of fixed nitrogen is also being pursued because of its important economic potential (ref. 5). This potential will probably become more and more important in the future as new and alternate sources for fertilizer nitrogen must be sought to replace and to conserve the limited available resources of natural gas. Natural gas presently represents the dominant raw material for production of fertilizer nitrogen through the ammonia synthesis process.

The mode of operation for this alternate control technique with nitrogen fixation is different from that of two-stage combustion with initial fuel-rich mixture for direct reduction of nitric oxide in the gas. The combustion in the high-temperature MHD burner must instead occur with a slight amount of excess air followed by a rapid expansion and cooling of the gas in the MHD generator in order to fix the maximum amount of nitric oxide in the gas. The fixed nitrogen is contemplated

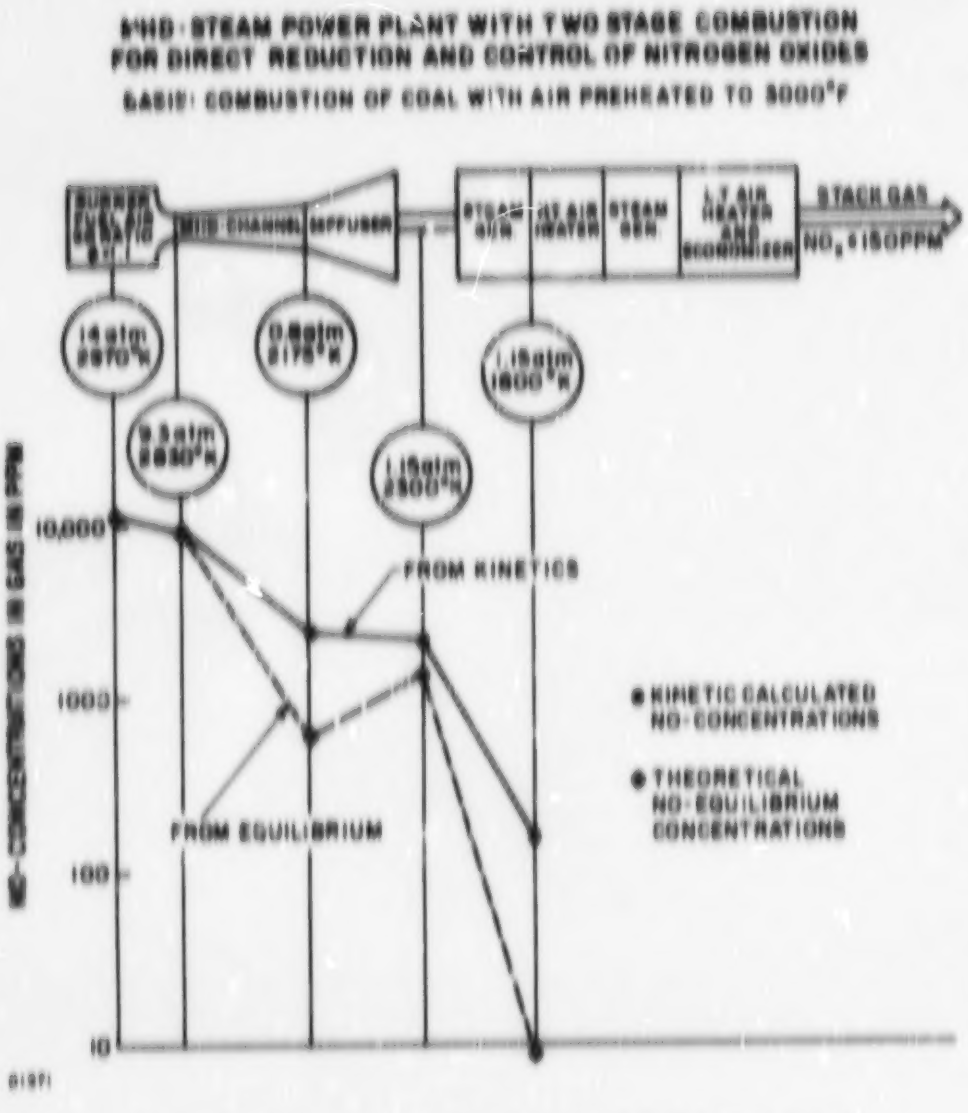

Figure 7. Kinetic history of nitric oxide in coal burning central station MHD power plant.

recovered by scrubbing of the effluent gas before the gas is emitted to the atmosphere (ref. 5). Preliminary investigations indicate that such a recovery process for fixed nitrogen can be very effective for removal of nitrogen oxides and also of any sulfur oxides from the effluent gas. The process has great economic potential because fixed nitrogen is a valuable fertilizer material. The economic attractiveness of the recovery process is unique to the high-temperature MHD process, since conventional power plants with their lower combustion temperatures cannot produce as much fixed nitrogen.

Expected emission factors for MHD power plants of the three major pollutants produced in combustion of coal are shown in table 2. These emission factors are

**Table 2. Comparative emission factors for coal burning power plants**
**(Basis for comparison, coal containing 3 percent sulfur burned with air.)**

| Pollutant | | Existing steam[a] | MHD | EPA standard |
|---|---|---|---|---|
| $SO_2$ | $lbs/10^6$ Btu | 4.587 | 0.045-0.018[b] | 1.2 |
| $NO_x$ | $lbs/NO_2/10^6$ Btu | 0.81 | 0.19-0.065[c] | 0.70 |
| Particulates | $lbs/10^6$ Btu | 1.054 | 0.10-0.01[d] | 0.10 |

[a] Emission factor from Public Health Service Publication No. 999-AP-42.

[b] Based on experimental demonstration at U.S. Bureau of Mines and Avco Everett Research Laboratory, Inc.

[c] Based on experimental demonstration at U.S. Bureau of Mines, Avco Everett Research Laboratory, Inc., and in Japan.

[d] Based on experimental demonstration at Avco Everett Research Laboratory, Inc., in U.S.S.R. and England.

compared to current EPA emission standards and to reported emission rates from conventional steam power plants.

*Economics*

Design studies with economic estimates of the capital costs of central station baseload power plants and costs of generating electricity in such plants have been conducted in order to assess the economic potential of MHD (ref. 14). It is recognized that such cost estimates can only be considered reasonable projections and that actual economics can only be established after construction and operating experience with large commercial installations have been obtained.

Estimated costs for generating electricity in coal burning MHD power plants are presented in table 3.

The cost estimates of MHD power plants are compared with those of generating electricity in conventional coal-fired steam power plants. Estimated costs have been added separately for cooling towers and for $SO_2$ removal from the gas for pollution control. For MHD power plants, costs related to gas cleaning are included in the basic plant estimated costs. Since early MHD plants here have been considered combined with steam power, comparative costs for cooling towers for this portion of the plant have been included. For fully developed and advanced power systems the combined use of a gas turbine is considered with no need for cooling towers. The economic attractiveness of MHD is clearly indicated. Actual savings can of course only be conjectured at this time. Fuel savings alone of $11 billion before year 2,000 have been estimated in a report published by the Office of Science and Technology in 1969 based upon 25 cents per thousand Btu (ref. 15). Present coal costs would triple this figure and further rising fuel costs and possibly more extensive use of MHD would increase savings further.

## STATUS OF MHD TECHNOLOGY

The development of MHD technology has spanned a period of 16 years and was pioneered in the United States. The major effort is now occurring in the U.S.S.R., but the U.S. effort has expanded in recent

Table 3. Comparative estimated costs of coal-burning 1,000-MWe power plants

(Estimate based on 1973 U.S. dollars.)

|  | Conventional Steam | MHD Early | MHD Developed |
|---|---|---|---|
| Efficiency, percent | 40 | 50 | 60 |
| Basic plant cost, $/kW | 250 | 235 | 170 |
| Basic generating cost - Mills/kWh |  |  |  |
| Capital charges (16 percent, 80 percent C.F.) | 5.71 | 5.37 | 3.89 |
| Fuel (35¢/MBtu) | 2.99 | 2.39 | 1.99 |
| Operation and maintenance | 0.30 | 0.30 | 0.30 |
| Seed |  | 0.08 | 0.05 |
| Basic generating cost | 9.00 | 8.14 | 6.23 |
| Pollution control cost - Mills/kWh |  |  |  |
| Dry cooling towers | 1.25 | 0.70[a] | 0[b] |
| Sulfur removal | 2.00[d] | 0.50[c] | 0.50[c] |
| Total add. generating cost | 3.25 | 1.20 | 0.50 |

[a] MHD - steam cycle, cost prop. to steam plant.

[b] MHD - gas turbine cycle, no steam condensation.

[c] Sulfur removal - seed regeneration cost.

[d] $SO_2$ - removal cost, Federal Interagency SOCTAP Report 1973.

years with the growing concern and recognition of the importance of improving fossil fuel technology.

The development work has centered on the MHD generator itself but major efforts have also involved important plant components and subsystems such as super-conducting magnets, combustion systems, air heaters, seeding and seed recovery systems, and methods for pollution control of sulfur and nitrogen oxides. For a detailed description of this technical development work, reference is made to numerous papers on the different subjects presented and reported on at National and International MHD Symposia (refs. 16,17).

The study of the MHD generator itself has proceeded along two complementary paths as illustrated by figure 8. The first has included construction and operation of relatively large experimental generators designed for short term operation. Parallel to this, studies have been conducted with experimental generators of lower power levels to establish the integrity and performance of electrodes, insulators, and channel mechanical design features for continuous long-term operation.

In the United States two large short-duration experimental MHD generators were built by AVCO and successfully operated in the middle sixties. One of these generators called the Mark V produced a gross power output of 32 MW. The other generator called the LORHD generator and located at the Arnold Engineering Development Center, Tullahoma, Tennessee, delivered an electrical output of 18 MW.

In addition to these larger short-duration experimental generators considerable work has been conducted with several fossil-fueled generators at much lower power levels. This work has mainly been carried out at AVCO Everett Research Laboratory, Inc., University of Tennessee, and Stanford University. It has provided valuable data and information for the engineering design and practical long-term operation of MHD generators under conditions appropriate to central station power plant

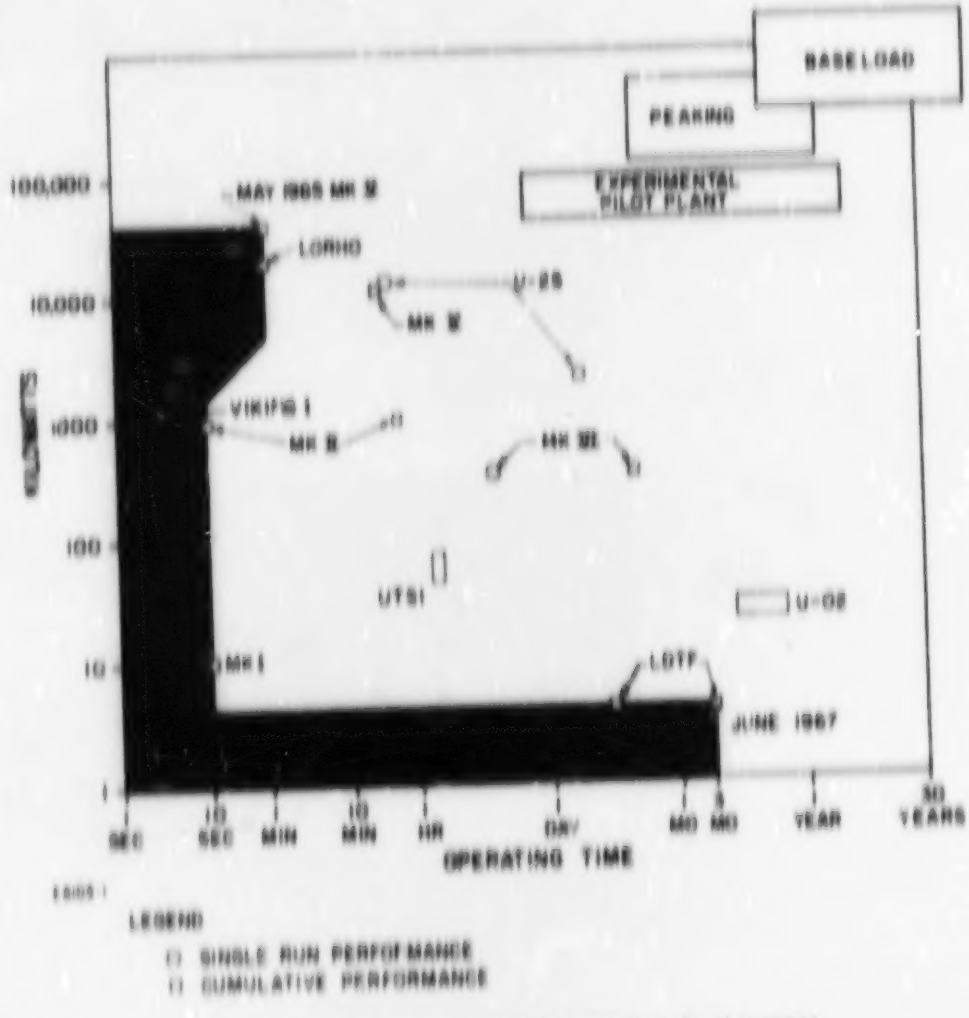

Figure 8. Performance in MHD generator development.

applications. Operation with experimental MHD generators at AERL and UTSI has demonstrated that MHD generators perform successfully with coal combustion products containing ash and can utilize coal slag as an effective and protective lining of the channel walls. Figures 9 and 10 show the slag coating of the channel and insulator walls obtained in the experimental operation at AERL. Work is now underway at AERL aimed at extending long-term channel operating experience with coal ash up to power levels of roughly 500 kW.

Different experimental MHD generators which have been designed, built, and operated during the MHD

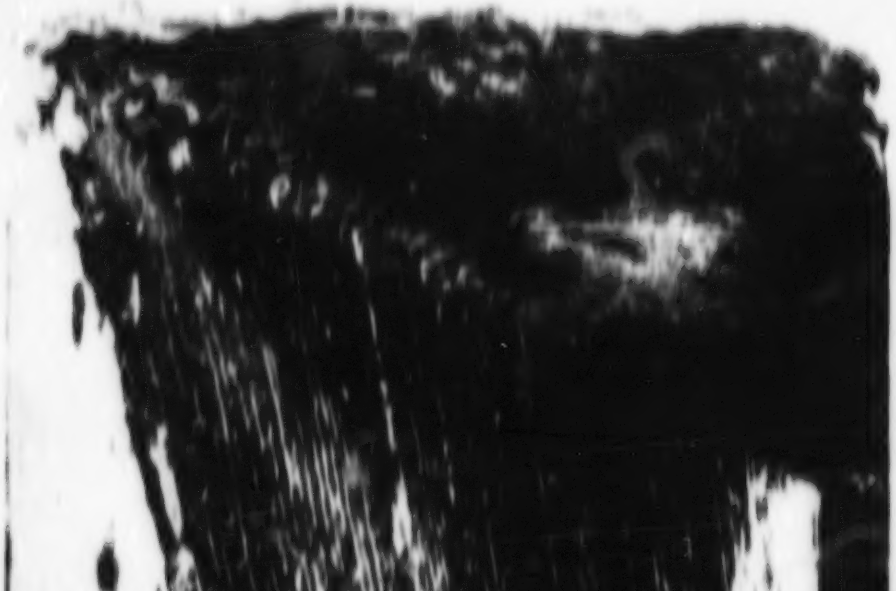

Figure 9. Slag deposit on MK VI diagonal channel wall.

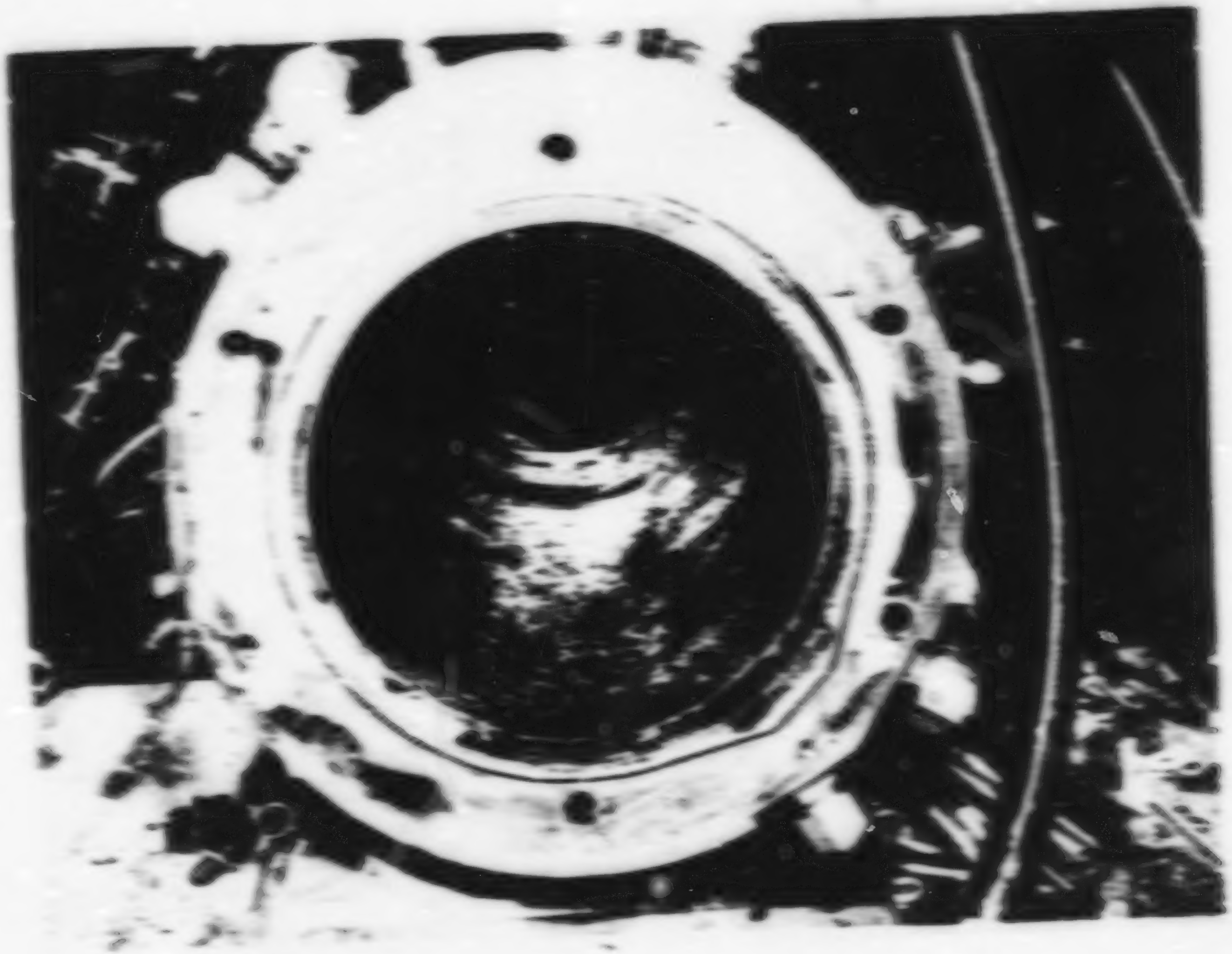

Figure 12. Slag deposit on MK VI combustor wall.

development program at AVCO Everett Research Laboratory, Inc., are shown in figures 11 and 12. Significant milestones achieved are indicated for the different experimental generators.

The MHD development work in the United States has been funded both by private industry and government. The work is being carried out principally at AVCO Everett Research Laboratory, Inc., MIT, Stanford University, the University of Tennessee, Westinghouse, GE, STD Corporation, the Bureau of Mines, and the Arnold Engineering Development Center.

By far the most impressive MHD effort today exists in the Soviet Union, with the strong support of the State Committee on Science and Technology and the joint sponsorship of the Academy of Sciences and the Ministry of Electrification. The most significant accomplishment to date has been the design, construction, and operation of a natural gas-fired pilot plant designed for an ultimate MHD generator output of 25 MW. It constitutes the first MHD pilot plant in the world feeding generated power directly into the Moscow electrical network system. Basic development for this plant was carried out in the smaller U-02 installation with 5 MW (thermal) capacity located in the center of Moscow. It is an integrated system experimental facility where development of the different elements of an MHD system continues. Officials of the U.S.S.R. have recently announced that design work now is underway on a large commercial demonstration MHD steam power plant incorporating an MHD generator of about 700 MW electrical output scheduled for operation in the early eighties. A cooperative MHD program has been initiated between the United States and the U.S.S.R. which is being coordinated by ERDA.

A serious effort in MHD development has also been underway in Japan for many years which incorporates a smaller scale integrated MHD power system test facility and a larger experimental MHD generator of 1,000 kW capacity. This larger experimental MHD generator has been operated with a superconducting magnet which produces a field strength of about 5 T.

The current MHD development work in the United States is being expedited and specifically directed to support the national objective of achieving a commercial MHD power demonstration in the late 1980's. A program plan to this aim is outlined in reference 18. The most critical goals of this program are identified as:

1. MHD generator demonstration,
2. MHD system demonstration, and
3. Commercial MHD combined cycle electric power generation.

## SUMMARY AND CONCLUSIONS

It is widely recognized that the development of MHD power generation would enable a much more effective utilization of our fuel resources, in particular, our vast coal reserves, with drastic reductions in pollution of air and water. It would serve the following important national goals:

1. More effective coal utilization,
2. Conservation of all types of fuels,
3. Reduced pollution of air and water,
4. Significant economic savings, and
5. Improved reliability of electric utility power systems.

The important potential advantages of MHD relative to existing technology are possible because of the inherent characteristics of the MHD process. It is a volume process which converts heat energy directly into electricity. The mechanical simplicity of the MHD generator with no moving parts makes it practical to handle high temperature gases produced from combustion of coal or other fuels with their inherent ash and sulfur impurities. Because of its high temperature capability, a much more efficient use of the fuel is possible. Prospects are that developed MHD power plants can attain 60 percent efficiency or even higher. Thus, 50 percent more electricity can be produced from the same amount of fuel as compared to the most efficient conventional steam power plants in use today.

The much better fuel utilization results directly in less rejection of waste heat so that thermal pollution can be drastically reduced. Detailed analysis of MHD power cycles has resulted in the development of MHD power plant designs which can eliminate thermal pollution of water and reduce air pollution to far below current EPA emission standards. Because MHD power plants can be designed to operate without condenser cooling water they can also be located in the western part of the country where coal is most abundant.

Experimental and analytical work by several MHD investigators in this country and abroad has shown that the emission of nitrogen oxides under realistic MHD power systems operating conditions can be reduced to very low levels and to only a smaller fraction of current EPA standards.

Experimental investigations have also verified that seed, together with any flyash impurities, can be removed from stack gas at very high efficiencies with conventional gas cleaning equipment resulting in strict control of particulate emission. Furthermore, experimental work at the Bureau of Mines has shown that sulfur

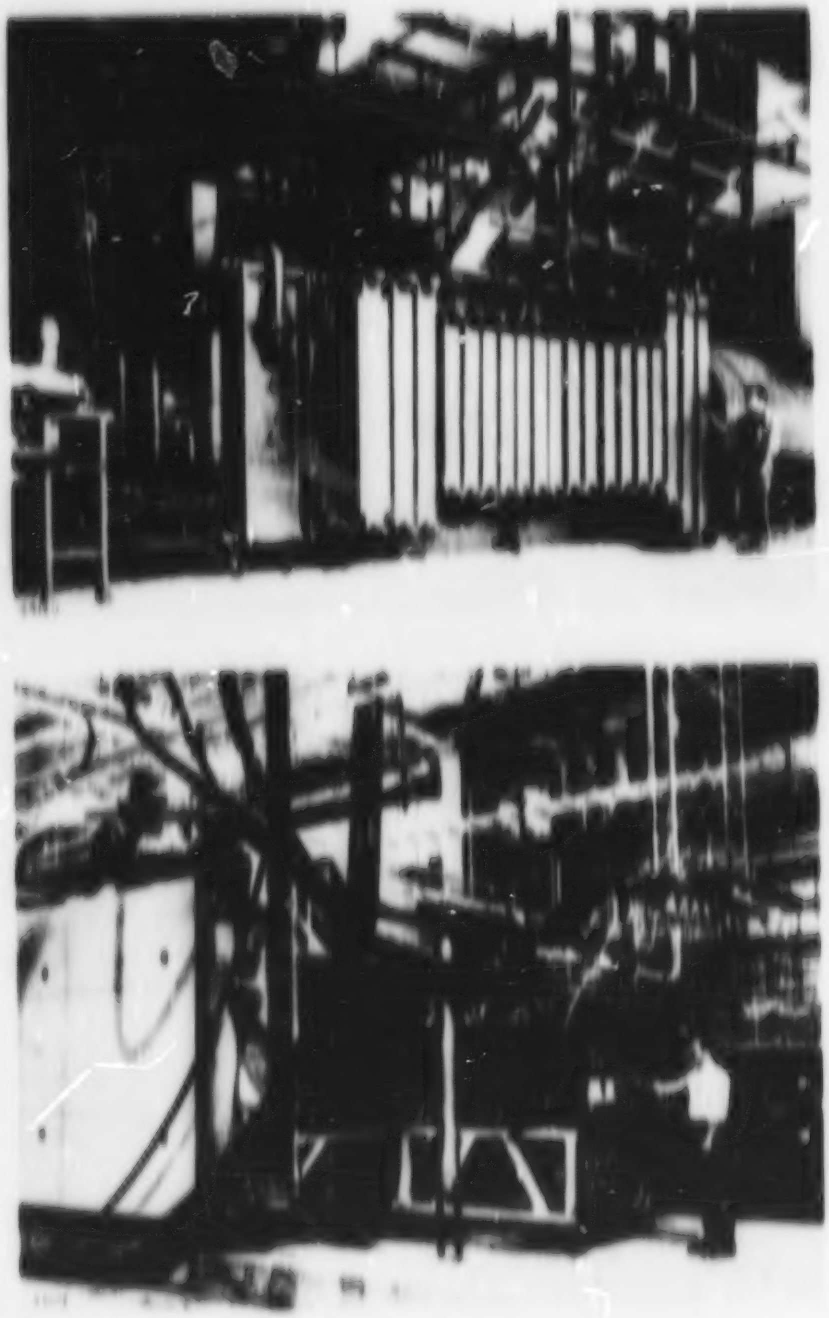

Figure 11. Two larger short duration experimental MHD generators: MK V: 1965, 32,000 kW, 1 minute, (AERL); LORHO: 1966, 18,000 kW, 1 minute, (built and operated by AERL for USAF at AEDC).

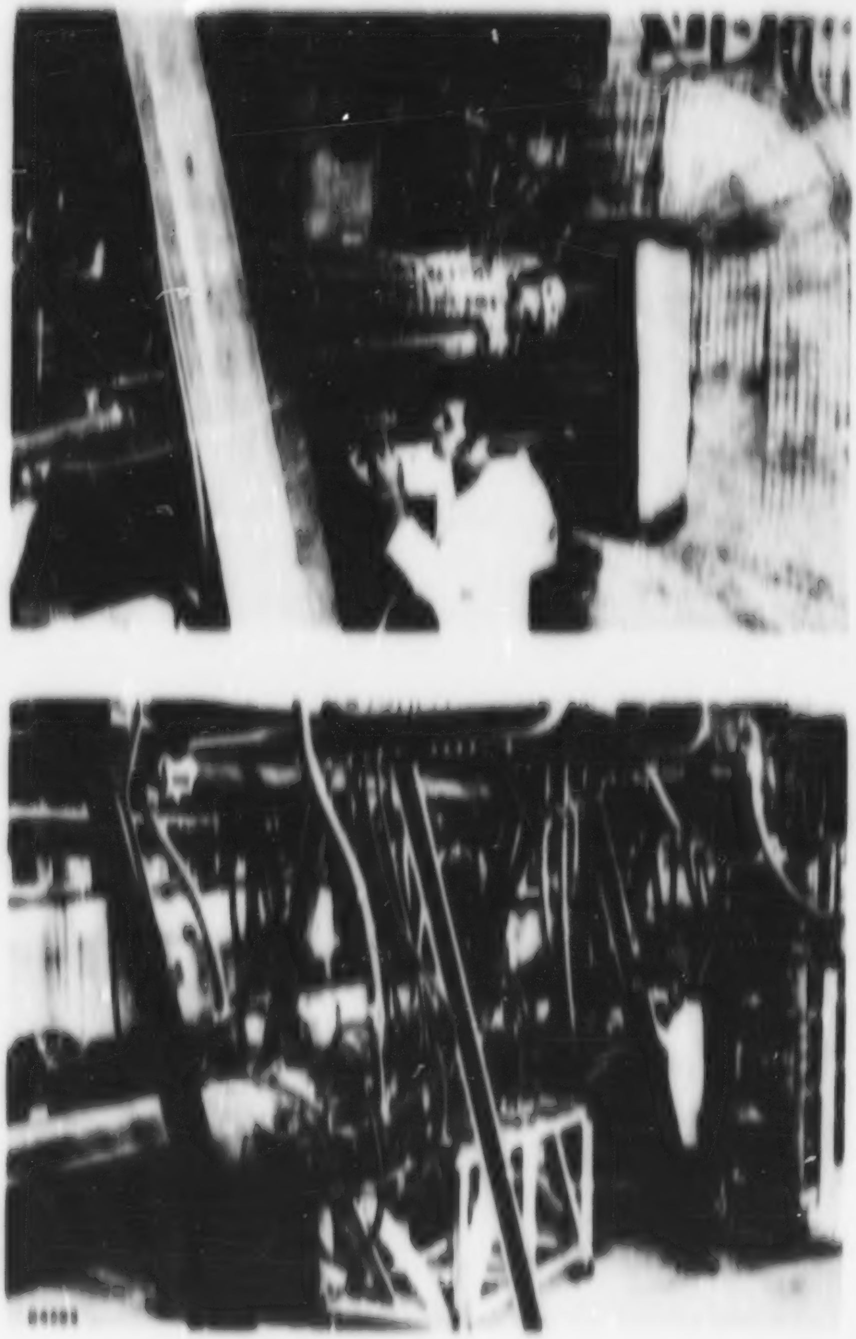

Figure 12. Long-duration experimental MHD generator at AERL MK VI - 1975, 120,000 kWh at an average power level of 300 kW.

oxides can be effectively removed from MHD generator exhaust gas together with recovery of seed and that elemental sulfur can be produced as a byproduct. This permits the combustion of coals having high sulfur contents in MHD power plants.

The conservation and environmental benefits offered by MHD with better fuel utilization, elimination of thermal pollution of water, and with reduction of air pollutants to far below EPA standards are perhaps the most attractive feature of MHD.

Its other major attraction is the projected favorable economics which has been clearly shown in many plant design and cost studies. This follows from a better utilization of the fuel and also from increased utilization of invested capital. Fuel savings alone could amount to several billions of dollars before the end of this century.

During the past 15 years, impressive research and development efforts have been conducted towards the development of coal-burning MHD power plants. Several experimental MHD power generators have been operated. Power outputs as high as 33,000 kW have been obtained from experimental MHD generators designed for short-term operation. Testing of experimental generators appropriate to operating conditions of coal-burning central station power applications have been conducted at power levels up to roughly 500 kW. The Mark VI experimental generator at AERL has to date produced close to 120,000 kWh in long duration testing at power levels between 300 and 500 kW for a total accumulated operating time of roughly 400 hours.

At the same time, other components required for the MHD power system have been developed and demonstrated experimentally. These include superconducting magnets, coal combustion systems, high temperature air heaters, and other subsystems. Throughout the development program, MHD power system design studies and analyses have been conducted in order to assess the technical and economic feasibility of MHD, its environmental effects, and guide the direction of the developmental work.

Further developmental work is necessary for commercial realization of MHD power generation. Such work should take full advantage of past accomplishments. A future MHD program has been proposed directed towards specific component and systems development problems. This incorporates a new Engineering Test Facility (ETF) to perform full MHD system tests. This is then followed by an MHD combined cycle commercial demonstration power plant.

To conclude, the development of MHD offers unique opportunities in helping to satisfy and balance society's need and demand for electric energy, conservation, and environmental quality.

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# ENERGY CONSERVATION THROUGH THE USE OF COMBINED-CYCLE POWER SYSTEMS

Albert J. Giramonti and William A. Blecher[1]

***Abstract***

*Analytical studies are being conducted to identify commercially feasible advanced technology combined-cycle power systems which would reduce consumption of fossil fuels, reduce utility-caused atmospheric and thermal water pollution, and produce low-cost electricity. Technological advances are described which could lead to gas turbines operating above 3,000° F and result in combined-cycle efficiencies approaching 55 percent (HHV) on clean gas or petroleum-based fuels. Because of the high cost and questionable availability of these fuels, the potential of combined-cycle systems using coal-derived fuels was established. One of the most attractive methods of utilizing coal would be to gasify it, remove the various pollutants, and burn the clean gas in a combined-cycle plant. Careful integration of the gasifier, cleanup, and power systems could result in coal-burning power stations using presently available technology which would produce power at costs competitive with conventional steam plants using stack gas cleanup. These systems would also have comparable efficiency, reduced thermal pollution, and lower emissions of $SO_2$, $NO_x$, and particulates. Systems utilizing advanced technology gas turbines would have even more attractive power costs, higher efficiency, and more favorable pollution characteristics.*

## INTRODUCTION

Uncertainties in the availability and cost of future fossil fuel supplies have created an urgent need for more efficient energy conversion machinery to best utilize available fossil fuels. It is expected that more economical use of fossil fuels than is now possible in electric utility steam stations will be provided by future utilization of combined-cycle power plants incorporating open-cycle gas turbines and waste heat recovery steam systems. The primary reason for this prospect is that gas turbines will operate at substantially higher peak cycle temperatures than steam stations.

Fundamental technological and economic obstacles prevent the utilization of steam conditions beyond the 3,400 to 3,500 psig, 1,000° F/1,000° F level, thus limiting steam station efficiencies to the 33-39 percent range depending on the stack gas cleanup and heat rejection procedures used. Conversely, industrial gas turbines with firing temperatures of 3,000° F are now envisioned as possible with sophisticated cooling schemes to insure component durability. With such firing temperatures, combined-cycle efficiencies approaching 55 percent together with high specific work output, are possible. The heat recovery-type steam system functions to convert gas turbine exhaust heat into shaft power, thus sidestepping what would otherwise be the need for excessively high gas turbine compression/expansion ratio to fully utilize future high firing temperatures.

The high performance potential of combined cycles is partly negated by the requirement for a clean gaseous or distillate type fuel. Unfortunately, domestic supplies of gas and oil are limited, and a serious gap between domestic supplies and demand for these fuels could persist for the next 20 years.

The energy crunch with its accompanying conservation measures has reduced somewhat the projected growth of the electric utility industry. Nonetheless, even conservative estimates (ref. 1) of the need for electrical energy in 1980 indicate that about 831 GW will be required, of which about 400 GW will be fossil fueled. By 1985, it is estimated that 1237 GW will be installed, approximately 680 GW of which will be fossil fueled. With all the projected additional installed capacity of fossil-fueled power systems, the already difficult problem of utility-caused pollution could become intolerable.

Two different approaches are open for utility consideration: (1) treatment of the power plant exhaust to remove pollutants, and (2) treatment of dirty fuels before combustion to remove harmful pollutants. Some stack gas cleanup processes show promise as a means of meeting the near-term EPA standard for $SO_2$ and particulate emissions. Currently, however, no commercial size stack gas cleanup system has been demonstrated that also removes significant amounts of $NO_x$. Fuel pretreatment would permit meeting all environmental regulations, but would also result in a significant increase in the cost of fuels delivered to the power generating system and introduce significant energy losses. In order to offset some of the increased fuel cost and the coal conversion inefficiencies, the thermal efficiency of the electric power generation should be increased as much as possible by using advanced-cycle systems.

Several feasibility evaluation studies of advanced combined-cycle power systems incorporating fuel gasification and cleanup have been conducted by the United

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Technologies Research Center. Widespread attention to the concept of the integrated gasifier/cleanup/power system was brought to focus by the publication in December 1970 of the United Technologies Research Center/Burns & Roe/FMC report entitled "Technological and Economic Feasibility of Advanced Power Cycles and Methods of Producing Nonpolluting Fuels for Utility Power Stations" (ref. 2). A current study for the EPA is putting into perspective the technical and economic characteristics of these advanced power systems based upon the current assessment of technological development in order to identify the potential environmental intrusion of the system (ref. 3) and to evaluate the merits of high-temperature fuel gas cleanup. The purpose of this paper is to present preliminary findings of the current EPA program and to identify the economic, environmental, and performance benefits that might be attained through the use of advanced combined-cycle power systems operating on distillate oil and coal-derived low Btu gas.

## ADVANCED COMBINED-CYCLE POWER SYSTEMS

One of the most promising advanced-cycle power systems consists of an open-cycle gas turbine used in combination with a heat-recovery steam system. Such a COmbined Gas And Steam (COGAS) power system is depicted in its simplest form in figure 1. A variety of combined-cycle configurations have been investigated, including supercharged and exhaust-fired, but the unfired waste heat recovery configuration appears to offer higher performance at lower cost than others. Unlike some present-day combined cycles in which the gas turbines are essentially air preheaters for the steam boiler, advanced cycles would utilize large industrial gas turbines operating at high turbine inlet temperatures. The technology basis for these gas turbines represents spinoff from the aircraft gas turbine industry. These gas turbines would produce approximately 60 percent of the net station electric output, and their exhaust gases would be directed into waste heat boilers which would generate steam for a steam turbine system producing the remaining output.

### *Advanced Technology Requirements*

Future industrial gas turbines used in combined cycles could be developed incorporating advanced aerospace technology in substantially improved large-capacity engines with appreciably higher thermal efficiency. While meaningful improvements in aerodynamic performance are projected for future gas turbines, the key to high efficiency is raising the turbine inlet temperature. The newer gas turbines currently being used in utility applications operate at temperatures around 1,800° F (see figure 2). Turbine inlet temperatures are

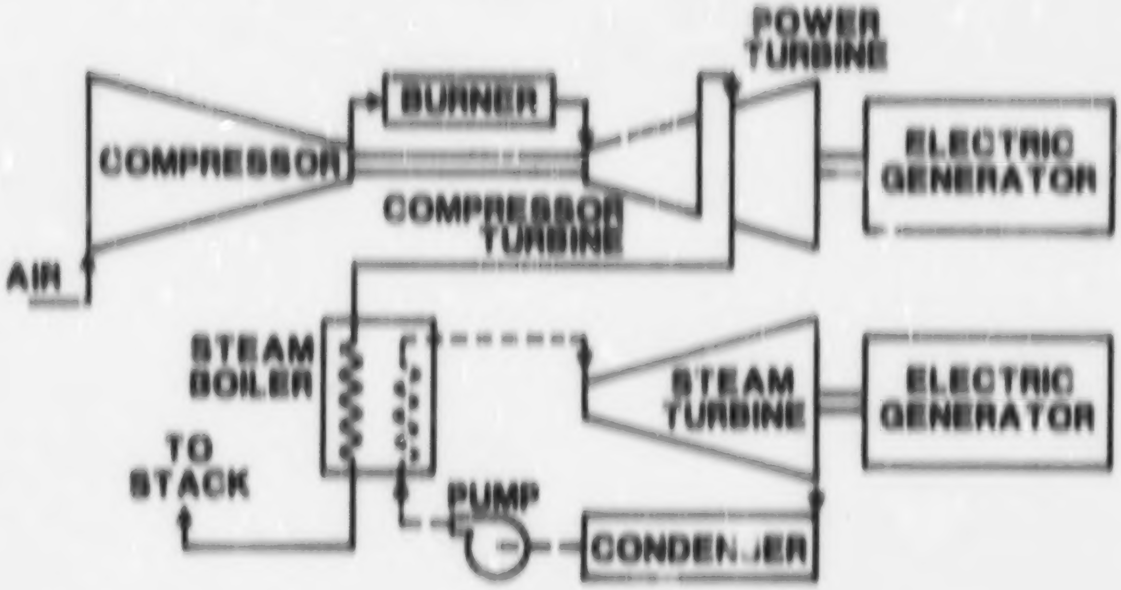

Figure 1. Combined-cycle power systems.

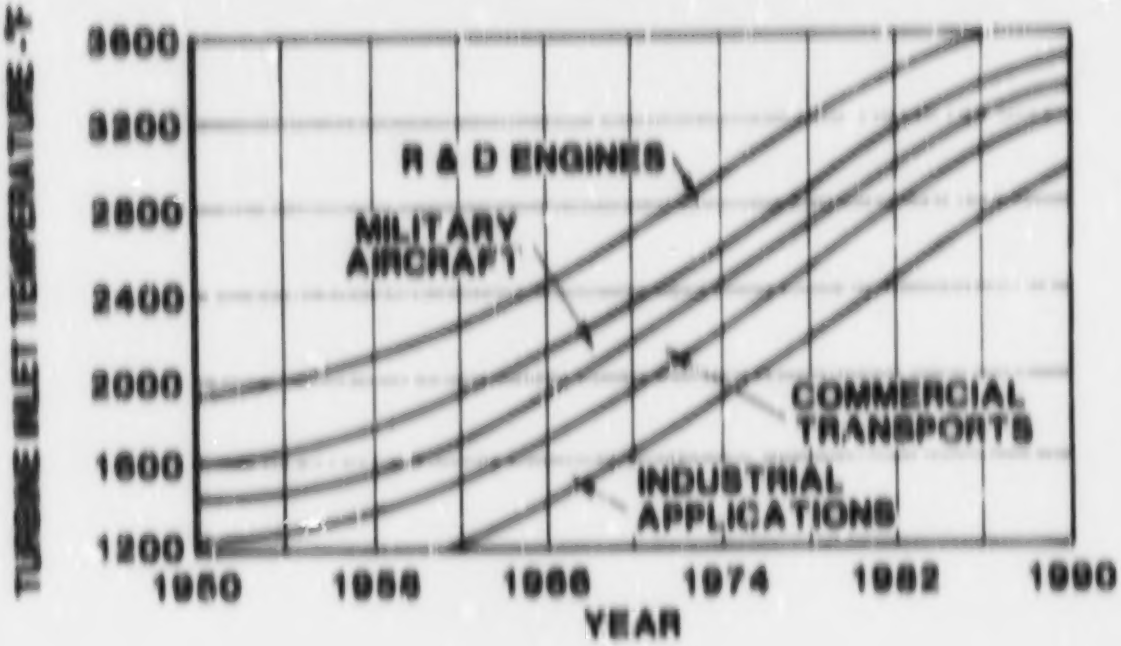

Figure 2. Estimated turbine inlet temperature progression.

expected to exceed 2,400° F by 1980 and 3,000° F by 1990. These increased temperatures will be a direct result of improvements in materials and blade cooling techniques. Future blade materials include advanced nickel, cobalt, and eutectic alloys. Recently, considerable attention has been given to ceramic materials such as silicon nitride and silicon carbide.

The most significant gains in turbine inlet temperature have been made possible by the application of various cooling techniques to the hot parts. Figure 3 summarizes some of the advanced air and water cooling configurations. Turbine cooling can be accomplished with coolants such as air, water, or liquid metals; but because of the complex cooling system designs and mechanical problems associated with liquid systems, air has been used exclusively in commercial engines. Turbine cooling schemes have progressed from simple convective cooling configurations incorporating cast, round, radial passages for vanes and single cavities for blades to advanced designs utilizing impingement, shower head, film, and transpiration concepts in several combinations. Advanced impingement-convection designs provide improved cooling of the inside surface of the leading edge and could be considered for operation up to 2,300° F. Complex shower head-film designs have been developed in which a layer of coolant is injected through slots and holes to form an insulating air blanket which protects the outside surface of the blade. These designs should be useful up to 2,800° F. By using a multipass thermosyphon blade with supercritical water as the coolant, temperatures in the 3,000° F range should be feasible.

*Performance Potential*

Performance estimates for future high-temperature gas turbines incorporating conventional impingement-convection cooling are presented in figure 4. Because of the high performance penalty associated with the turbine cooling air requirements, gas turbine efficiency does not increase appreciably with increased turbine inlet temperature. However, the specific power (net power per unit air flow) does increase significantly. Specific power is a measure of the amount of work which can be done by a given size machine and is, indirectly, a guide to cost.

A secondary advantage of higher turbine inlet temperature is higher exhaust temperature resulting in higher performance for the steam portion of the combined cycle. For waste-heat recovery systems, the most

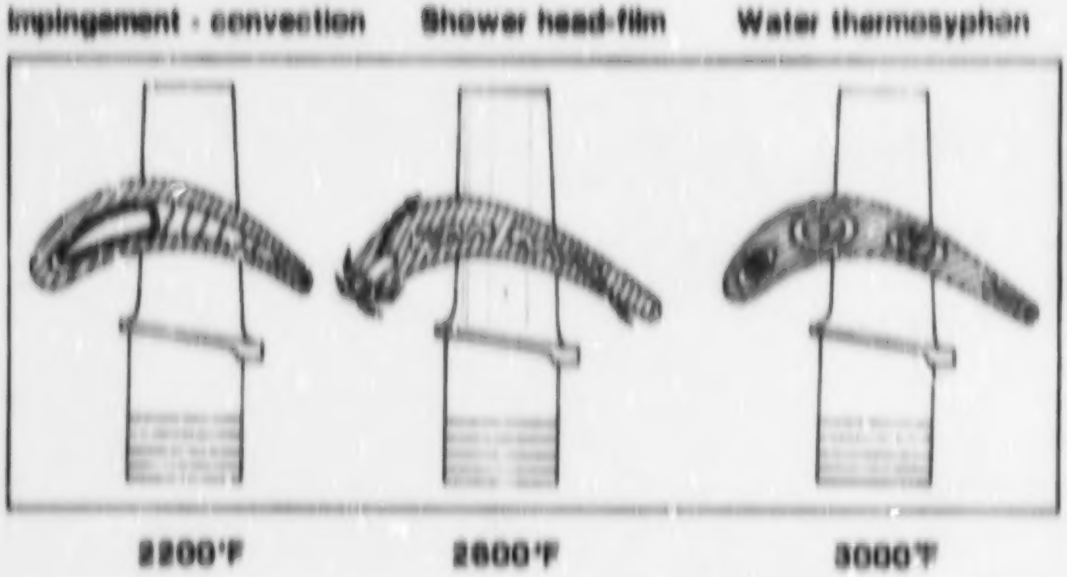

Figure 3. Advanced turbine cooling configurations.

attractive steam system would have a relatively simple cycle configuration. Regenerative feedwater heating would be limited to a single deaerating feedwater heater so that essentially all the steam would pass through the turbogenerator and be condensed.

The potentially high performance of the combined cycle is one of its most attractive attributes. Referring to a system using conventional distillate-type fuels and conventional air cooling techniques, performance levels as shown in figure 5 should be possible. At 2,200° F turbine inlet temperature, a level which should be attainable in baseload turbines in the late 1970's, an efficiency of 43.5 percent could be realized. As turbine inlet temperatures increase, efficiencies also increase, and it should be possible to approach 48 percent at inlet temperatures of approximately 2,600° F. The performance values presented in figures 4 and 5 are based on use of conventional shower head-film cooling using air bled from the compressor and sent directly to the part, either static (vane) or rotating (blade), to be cooled. Also, maximum metal temperatures are limited to 1,500° F.

With use of other cooling techniques, system efficiency could be increased to about 55 percent. This is depicted in figure 6, where system efficiency changes with various cooling schemes are presented.

By the simple expedient of cooling the compressor bleed air to about 300° F (from perhaps 800° F at compressor discharge) before using it for cooling, a lesser amount of air would be required and an efficiency increase would result. If the static parts were cooled by water or made from some temperature-resistant material such as ceramics, the amount of air bleed would be further reduced to that required for rotating parts alone and the efficiency would increase. If both static and rotating parts were water cooled, only air required for buffering and disc cooling would be used and further efficiency gains could be expected, the exact value being a function of type of water cooling selected. Finally, if the static and rotating parts were ceramic, no heat would be removed from the gas path by cooling and the largest efficiency gain, to almost 55 percent, could be realized.

While ceramics offer much incentive, their development in large sizes poses problems and it appears that improved cooling technology offers a more effective near-term solution. Advanced cooling methods are not without technical difficulties; e.g., water cooling could

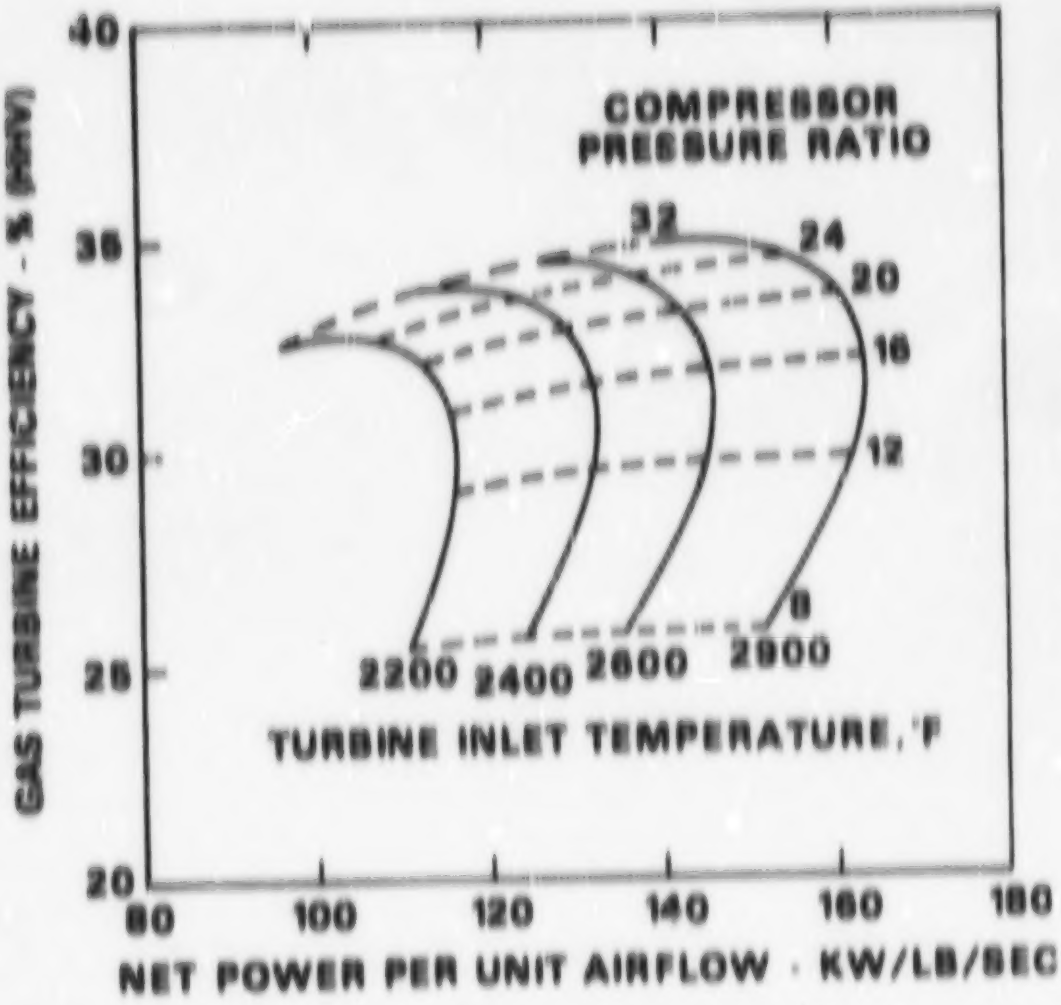

Figure 4. Gas turbine performance (Distillate fuel oil, conventional air cooling).

require treatment of water beyond the level typically associated with power stations.

## INTEGRATED COMBINED CYCLE/ GASIFICATION SYSTEMS

Combined-cycle power systems, as with other advanced technology gas-turbine-based power systems, require fuels of utmost cleanliness. The level of this cleanliness is usually well beyond that required by environmental regulations. When considering the use of coal as fuel for such power systems, it is apparent that considerable processing and cleanup must precede its introduction into the engine. Low-Btu fuel gas, produced by gasification and desulfurization of high-sulfur coal, appears to be very attractive for use in these power systems. The following paragraphs contain brief descriptions of selected advanced power and fuel conversion processes which could be considered for use in integrated combined-cycle/gasification power systems, parametric performance estimates for future systems, a

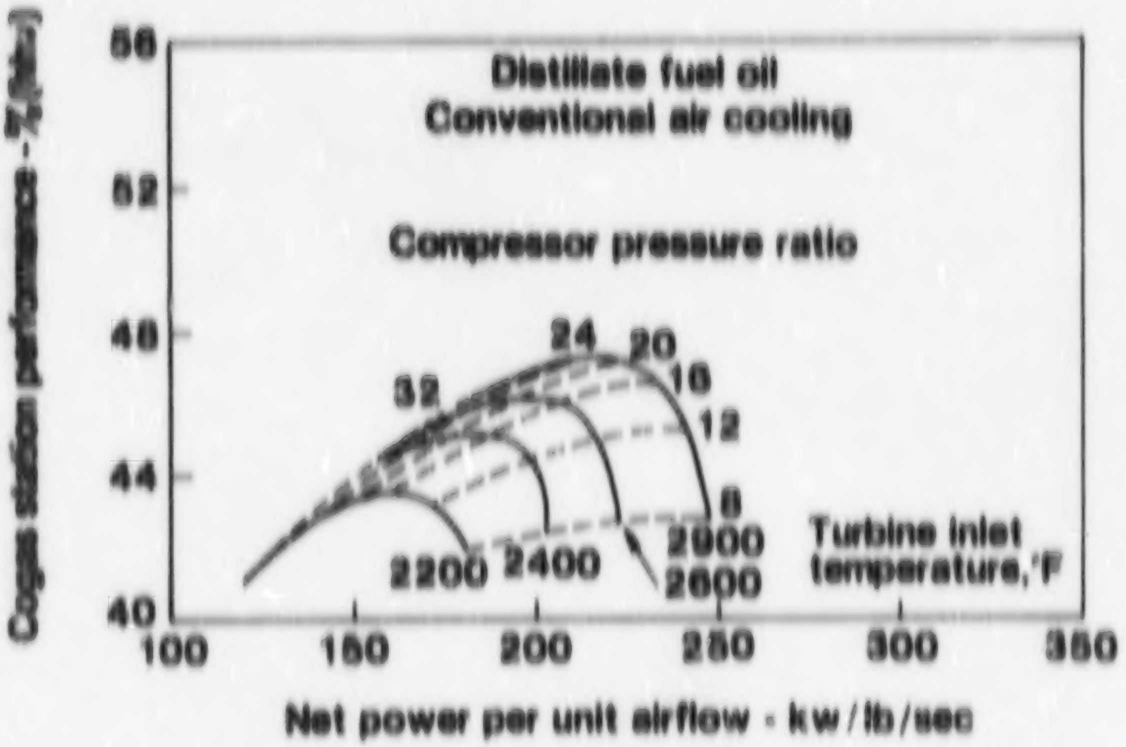

Figure 5. COGAS station performance.

summary of environmental pollutant emissions, and preliminary economic comparisons.

*Integrated System Descriptions*

During recent investigations of integrated combined-cycle/gasification systems (ref. 3), four combinations of coal gasifiers and fuel gas cleanup processes were examined. They are: (1) Bureau of Mines stirred-bed gasifier followed by Selexol low-temperature cleanup, (2) Bureau of Mines gasifier followed by Sintered Iron Oxide hot gas cleanup, (3) BCR two-stage entrained flow gasifier followed by Selexol cleanup, and (4) BCR gasifier followed by Conoco hot cleanup. Selection of these processes was made to permit a meaningful comparison of hot and cold cleanup processes in conjunction with realistic gasification systems and is not meant to imply that these gasification and cleanup processes are superior to other prospective processes.

Those systems using the Bureau of Mines gasifier are considered first generation because they have the potential for commercial operation during the early 1980's. Those systems using the BCR gasifier are considered second generation because they have the potential for commercial operation by the late 1980's. In a similar manner, the gas turbine technology judged to be representative of engines used in first generation systems is conventional shower head-film cooling at a turbine inlet temperature of 2,200° F and a pressure ratio of 16:1. For second-generation systems, the use of ceramic vanes with conventional blade cooling at a turbine inlet temperature of 2,600° F and a pressure ratio of 24:1 was selected.

The Bureau of Mines/Selexol integrated system is shown schematically in figure 7. The gasifier is supplied with air and steam from the combined-cycle system. Compressor bleed air is used to generate process steam prior to entering a boost compressor and saturated steam is extracted from the high-pressure section of the waste-heat boiler. Because of the tar content, the gasifier exit stream is quenched and the tars separated and returned to the gasifier. The gas leaving the water quench is saturated with water vapor limiting the amount of regeneration of the fuel gas which is possible. However, the

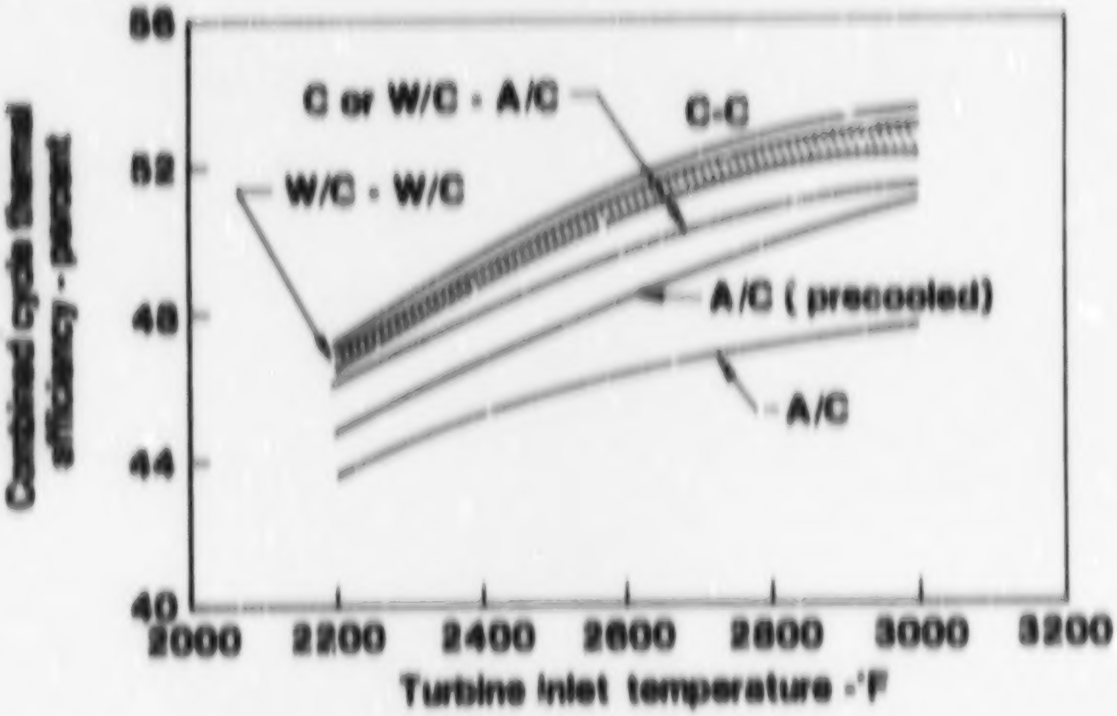

Figure 6. Combined gas turbine and steam station performance (A/C = air cooled; W/C = water cooled, C = ceramics).

latent heat of the water vapor is quite significant and is used in the reboiler of the sour water stripper. After regeneration with the product gas, the remaining heat is rejected to ambient to lower the temperature prior to a water scrub and Selexol cleanup tower. Condensate from the Selexol stripper and the gas cooling process along with water from the scrubber must be processed in the sour water stripper. In the ammonia recovery process, $H_2S$ absorbed in the water is recovered and sent to the Claus plant. After regeneration, the clean fuel gas is fed to the combined cycle which functions normally except that steam is extracted from the high-pressure section of the boiler for use in the gasifier and ammonia removal unit. Also, steam raised in the gasifier jacket is used to supplement the waste-heat boiler. Because the fuel gas steam provides heat directly to the sour water stripper, the quantity of low-pressure steam required is relatively small and the steam raised in the gasifier bleed air stream is sufficient to satisfy this need.

The Bureau of Mines/Sintered Iron Oxide integrated system is shown in figure 8. Because the tar in the product gas does not affect operation of the hot cleanup system, the water quench can be eliminated. The flow schematic diagram is quite simple due to the lack of regeneration and elimination of the water scrub and tar recycle. Gasifier performance is enhanced by not recycling the tar since it permits operation at lower air- and steam-to-fuel ratios. The net cleanup system reactions are exothermic both during absorption and desorption, adding sensible energy to the fuel and enabling the recovery of heat in the form of process steam from the regenerator off-gas. However, the sulfur comes off the iron oxide as $SO_2$ and in the sulfur recovery system must be concentrated and a portion reduced to $H_2S$ so that it can be used to form elemental sulfur in a Claus unit. This process uses a considerable amount of fuel and process steam. As a result, even with the steam raised in the process, a significant amount of low-pressure steam

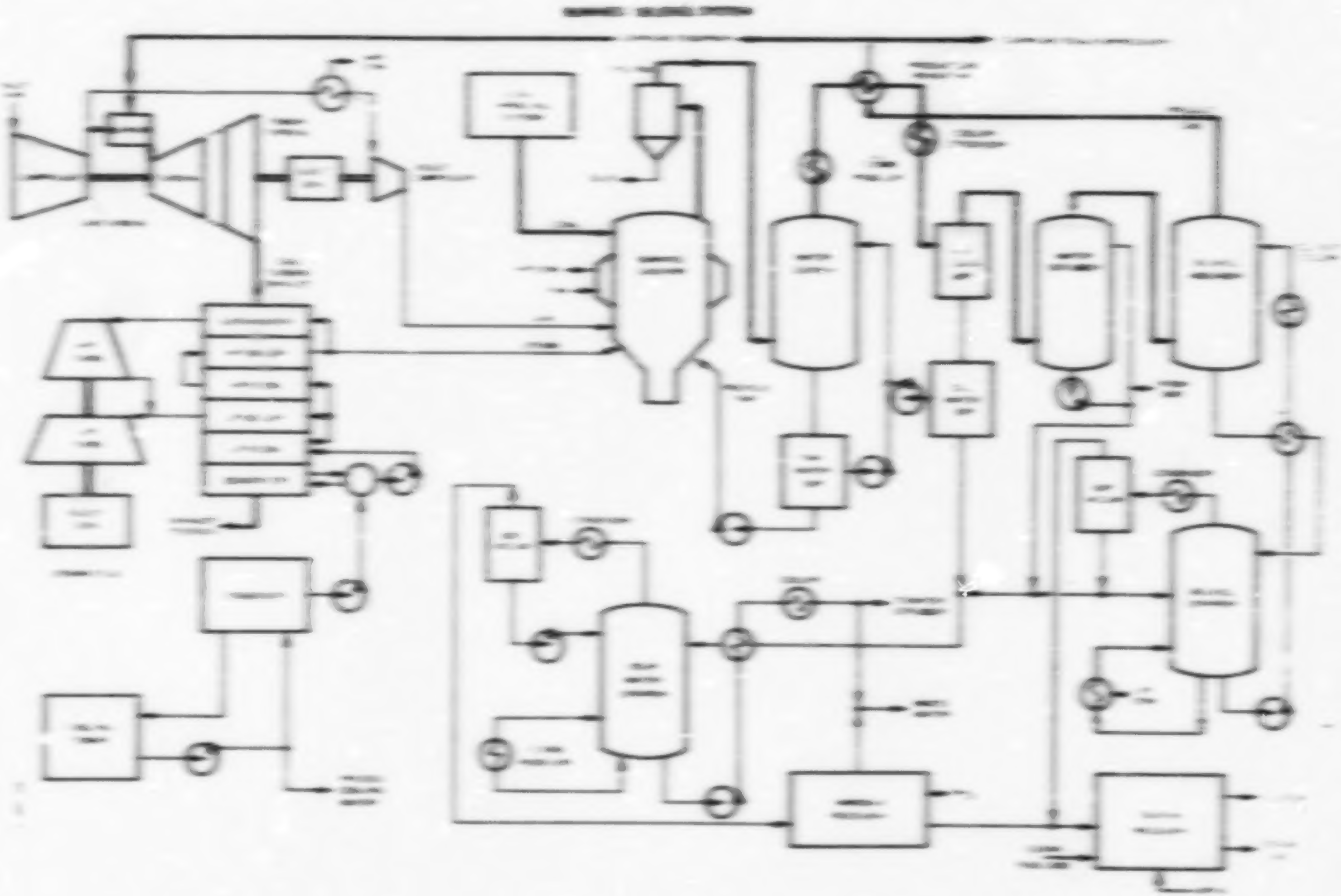

Figure 7. Sulfinol/Selexol system.

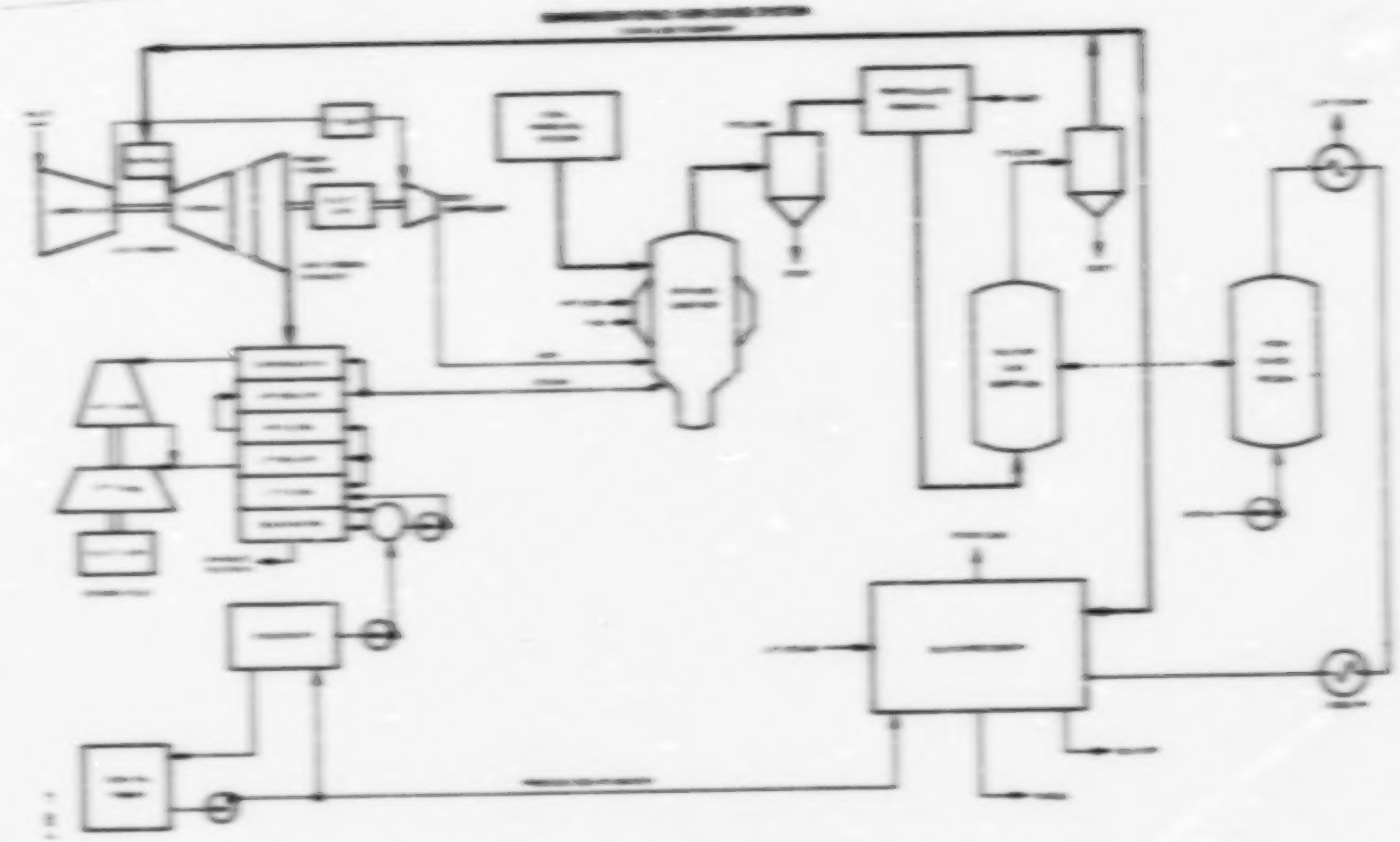

Figure 8. Alumina/Sintered Iron Oxide system.

must be taken from the waste heat boiler to satisfy these requirements. The lower gasifier steam requirement means that nearly all the heat needed to raise the gasifier steam can be taken from the gasifier cooling jacket. The system suffers from the inability to remove ammonia from the gas and the uncertainties associated with particulate removal. Because ammonia would not present a problem if it were reduced to its equilibrium concentration, the possibility of catalytic decomposition was considered. Iron oxide appears to be potentially capable of catalyzing the decomposition while removing hydrogen sulfide. This would remove the primary source of nitrogen; however, the tars would contain some nitrogen and sulfur compounds that would not be removed by the cleanup system.

With the BCR/Selexol system, shown in figure 9, it is possible to both regenerate and extract useful heat from the gasifier exit stream. Ammonia and $H_2S$ removal are quite similar to the Bureau of Mines system, but the Selexol system is complicated by a high percentage of COS in the gas to be processed. Because COS is about one third as soluble as is the $H_2S$, its presence in the gas stream requires that the process be tailored specifically for removal of COS. The utilities for this system reflect this situation. A significant amount of heat is recovered from the gasifier jacket and the high-temperature gasifier exit stream. This heat is used to raise high-pressure steam which supplements the high-pressure section of the waste heat boiler by adding about 50 percent to the steam raised there. After the steam for the gasifier is extracted, the net increase in steam available for the turbine is about 25 percent. All of the low-pressure process steam requirements are met by steam raised in the boilers located upstream of the boost compressor and downstream of the fuel gas regenerator.

In the BCR/Consol system, shown in figure 10, the gas stream arrangement is very simple and the omission of a water scrub makes process steam requirements quite low. As a result, it is possible to raise high-pressure steam in boilers located upstream of the boost compressor and in the transport gas stream prior to the $CO_2$ removal unit. The low-pressure process steam needed to supplement that raised within the cleanup and sulfur recovery system can be supplied by a boiler located between the high-pressure boiler and boost compressor. The high-pressure steam is used to supplement the waste heat boiler and balances the amount of superheated steam extracted for injection into the gasifier.

### *Integrated System Performance*

A summary of the calculated performance characteristics for each of the four systems described is given in table 1. The performance of the second generation gasification and cleanup systems mated with a first generation power system is also given to permit a gross comparison of the gasification and cleanup systems. In addition, the integrated station performance variations as a function of gas turbine pressure ratio are shown in figures 11 and 12 for first and second generation power systems, respectively. To provide consistency and a basis of comparison, both figures include the performance estimates for distillate fired combined cycles.

Looking at overall net plant efficiency, it is clear that there are two significant factors in performance improvement: turbine inlet temperature and high-temperature cleanup. Increasing turbine inlet temperature from 2,200° F to 2,600° F produces a 13 percent improvement in cycle efficiency. For the second generation gasification systems, the difference in performance between high- and low-temperature cleanup is about 18 percent. Detailed analysis of the high-temperature cleanup case reveals that only 7 percent of the gain is due to the high-temperature operation, approximately 7 percent is due to a higher cleanup process efficiency (lower requirements for process steam and auxiliary power), and the remaining 4 percent is due to the lack of ammonia removal provisions. Even the 7 percent gain for high temperature could be reduced by development of fuel gas regenerators capable of operating above 1,000° F and by rehumidification of the fuel gas stream to replace the water vapor condensed during the cool down process.

### *Integrated Station Cost Comparison*

Historically, the U.S. electric utility industry successfully reduced the cost of generating power by utilizing the latest available technology and taking advantage of economies associated with large-scale generation facilities. This era of decreasing cost of electricity has ended, and we are now in a new era with rising costs. This unfortunate situation is a direct result of rapidly rising construction and fuel costs combined with public demands for effective control of atmospheric and thermal water pollution. Rising costs plague all methods of power generation, both fossil and nuclear. Because of this situation it is extremely difficult to accurately estimate the capital and operating costs of future power systems.

Nevertheless, preliminary estimates of capital and operating costs were made (see table 2) for each of the four selected systems. In addition, the costs of power generation in a conventional plant with stack gas cleanup and in a gasified coal fired steam plant have been estimated to provide a basis for comparison. A summary of total power generation costs for the six systems is presented in figure 13 in terms of base coal cost. These

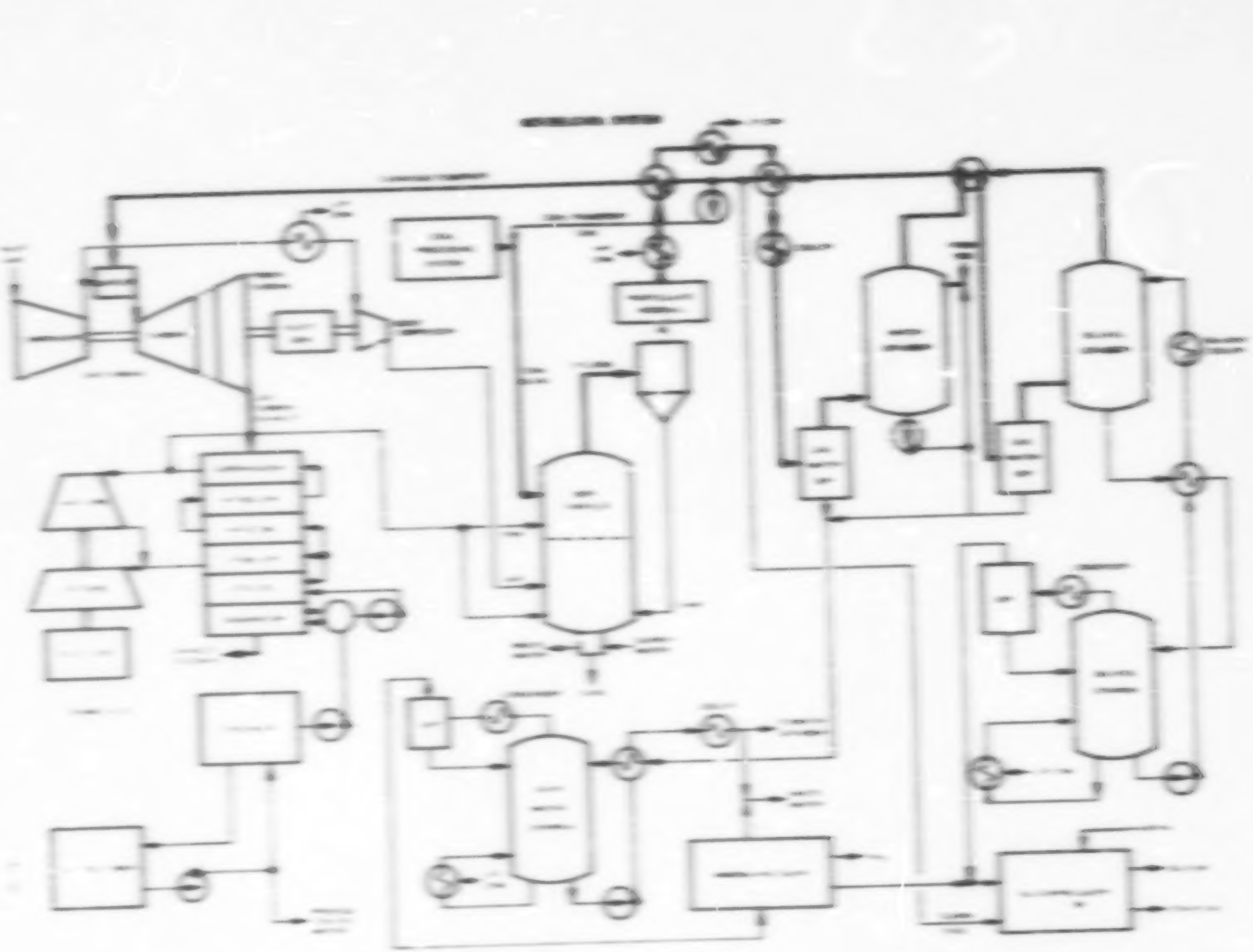

Figure 8. SCR/Selexol system.

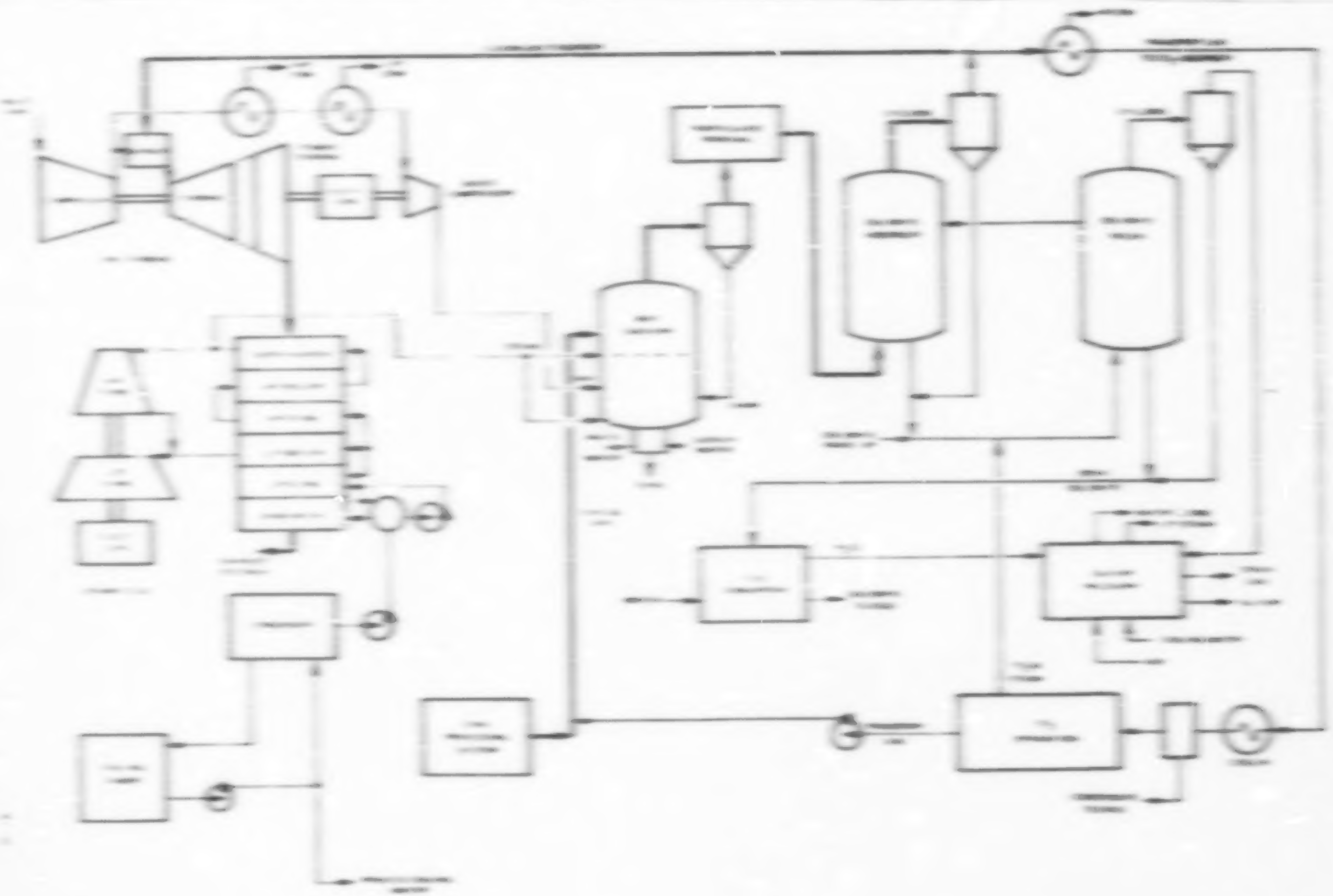

Figure 52. BCR/Conoco system.

Table 1. Integrated systems performance summary

| | First generation | | Second generation | | Second generation gasification<br>First generation power system | |
|---|---|---|---|---|---|---|
| | BGW/<br>Selexol | BGW/<br>Iron oxide | BCW/<br>Selexol | BCW/<br>Conoco | BCW/<br>Selexol | BCW/<br>Conoco |
| Gas turbine | | | | | | |
| Turbine inlet temperature - °F | 2,200 | 2,200 | 2,600 | 2,600 | 2,200 | 2,200 |
| Compressor pressure ratio | 16 | 16 | 24 | 24 | 16 | 16 |
| Exhaust temperature - °F | 976 | 913 | 1,107 | 1,115 | 913 | 920 |
| Output power - MW | 595.4 | 626.2 | 726.6 | 857.6 | 642.3 | 757.6 |
| Steam cycle | | | | | | |
| Steam temperature - °F | 876 | 813 | 1,000 | 1,000 | 813 | 820 |
| Steam pressure - psia | 1,250 | 1,250 | 1,250 | 1,250 | 1,250 | 1,250 |
| Condenser pressure in. Hg. Abs. | 4.0 | 4.0 | 4.0 | 4.0 | 4.0 | 4.0 |
| Net steam cycle output - MW | 223.8 | 208.1 | 253.3 | 296.6 | 273.5 | 271.4 |
| Net steam cycle efficiency | .280 | .252 | .307 | .327 | .282 | .279 |
| Gasifier and cleanup system | | | | | | |
| Coal feed rate - lb/hr | 703,000 | 702,000 | 700,000 | 700,000 | 700,000 | 700,000 |
| Air/coal ratio | 3.073 | 2.600 | 3.088 | 3.000 | 3.088 | 3.088 |
| Steam/coal ratio | .405 | .389 | .567 | .567 | .567 | .567 |
| Air preheat temperature - °F | 800 | 800 | 800 | 800 | 800 | 800 |
| Steam temperature - °F | 584 | 584 | 1,000 | 1,000 | 913 | 920 |
| Steam pressure - psia | 1,250 | 1,250 | 1,250 | 1,250 | 1,250 | 1,250 |
| Gasifier exit temperature - °F | 1,000 | 1,000 | 1,800 | 1,800 | 1,800 | 1,800 |
| Cleanup system exit temperature - °F | 265 | 1,070 | 1,000 | 1,700 | 1,000 | 1,700 |
| Fuel gas higher heating value Btu/SCF | 160.3 | 165.9 | 159.3 | 135.8 | 159.3 | 135.8 |
| Integrated station | | | | | | |
| Gross power - MW | 819.2 | 834.3 | 1,074.9 | 1,154.2 | 915.8 | 1,029 |
| Boost compressor power - MW | 43.4 | 36.1 | 40.1 | 40.2 | 40.1 | 40.2 |
| Gasifier & cleanup aux. power - MW | 28.2 | 36.5 | 59.7 | 27.6 | 58.7 | 27.6 |
| Plant auxiliaries - MW | 10.6 | 10.2 | 13.6 | 14.5 | 12.5 | 13.1 |
| Net plant output - MW | 737.0 | 751.5 | 907.5 | 1,071.9 | 804.5 | 948.1 |
| Net plant efficiency (HHV-coal) | .314 | .320 | .360 | .425 | .319 | .376 |

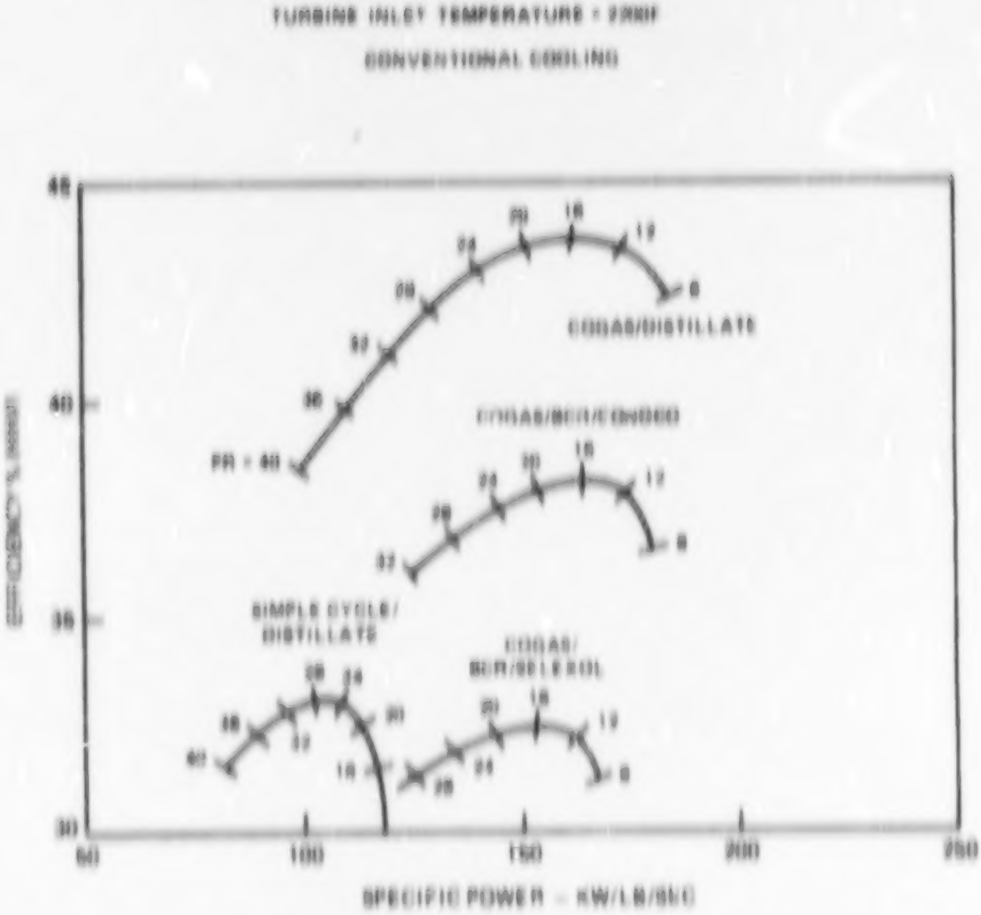

Figure 11. Performance estimates for first generation turbine systems.

estimates are based on mid-1974 costs with escalation through the construction period. It is quite clear that the most attractive gasification/cleanup system for use with a combined cycle powerplant is the BCR/Conoco combination. This second generation combination appears capable of generating electric power at much lower cost than any other alternative, including steam with gasification and steam with stack gas cleanup. The other combinations are only marginally competitive with the steam alternatives.

It is interesting to note that the relative cost comparisons do not change greatly over the coal cost range of interest. Also, for a given gasifier and power system, the low-temperature cleanup is more costly than the high. This is mostly due to the lack of ammonia removal and associated equipment in the high-temperature cleanup systems. In the case of the BCR/Conoco system, however, that effect is amplified by the improved efficiency of the gasifier/cleanup combination, resulting in a greater plant output over which to amortize the capital cost. Changing from first to second generation systems also tends to decrease initial cost due to a higher gas turbine specific output, which results in a lower cost per kilowatt of the power system.

*Environmental Impact of Integrated Stations*

The four integrated power stations previously described were used as a basis to identify the various pollutants which would be associated with this type of powerplant. A summary of the estimated environmental impact of the four selected systems is given in table 3.

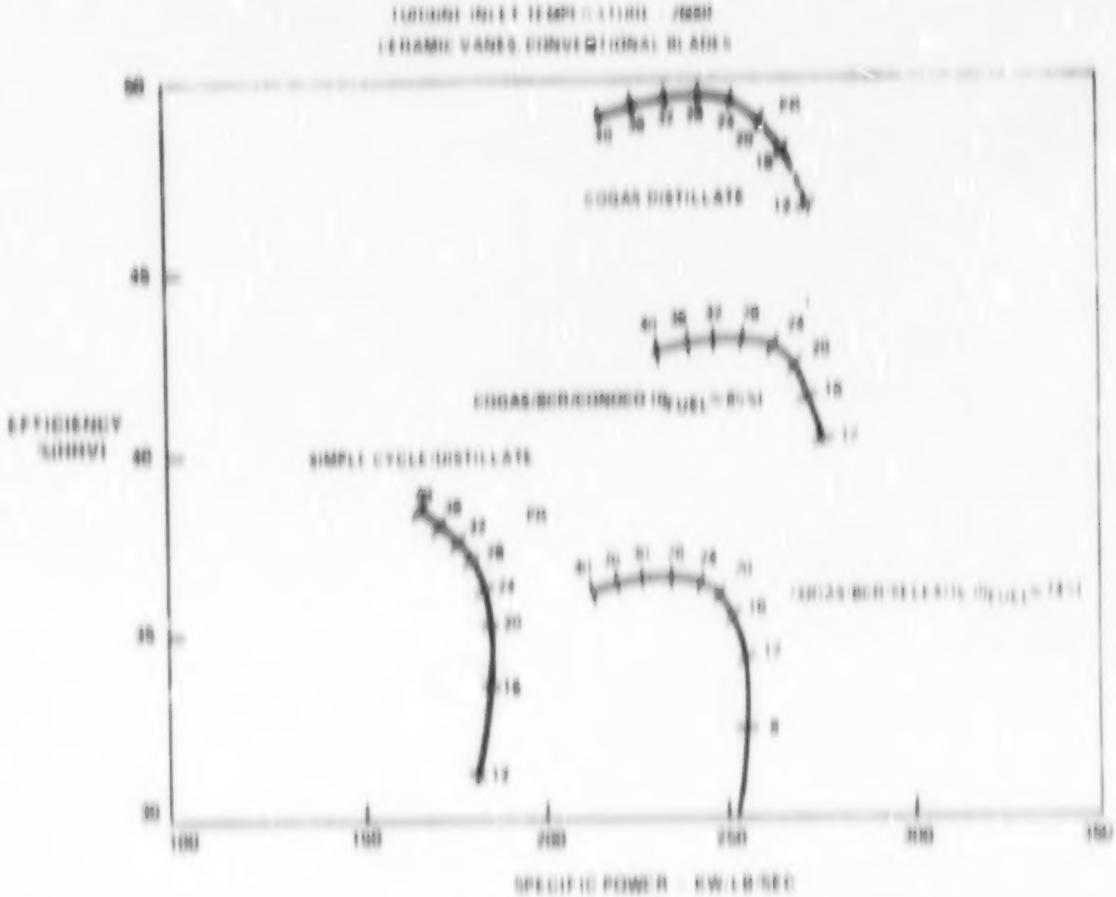

Figure 12. Performance estimates for second generation turbine systems.

Waste water, thermal, $SO_2$, $NO_x$ particulate, solids, sulfur, and ammonia discharges from the gasification/cleanup system and from the combined cycle power systems are shown.

It is apparent from the table that $SO_2$ emissions from the sulfur recovery plant could be significant (60 percent to 85 percent of total sulfur emissions). However, commercially available tailgas treating processes could be used to further reduce sulfur levels in these cases. All sulfur remaining in the fuel (as $H_2S$ or in tar vapors from the Bureau of Mines gasifier) were assumed to be converted to $SO_2$ during the combustion process. Resulting total sulfur emissions should all be less than the EPA limit (1.2 lb $SO_2$/MMBtu) for coal-fired powerplants.

The formation of nitrogen oxides ($NO_x$) is a much more complex problem than that of sulfur oxides. Two mechanisms, one involving nitrogen in the air and the other involving fuel nitrogen, contribute to the formation of nitrogen oxides during combustion processes. The thermal mechanism dealing with atmospheric nitrogen is reasonably well understood and many analytical models have been developed to predict $NO_x$ formation using this mechanism. Additional nitrogen oxides would be produced by nitrogen-bearing compounds ($NH_3$, HCN, pyridines, etc.) in the fuel. These compounds are produced from the nitrogen-bearing compounds in coal during the initial gasification process. They would be removed by low-temperature cleanup systems, but

Table 2. Cost comparison for coal-fired power plants

| | Combined-cycle [illegible] Selexol | Combined-cycle [illegible] Iron oxide | Combined-cycle BCR Selexol | Combined-cycle BCR Conoco | Steam stack gas cleanup | Steam BCR Conoco |
|---|---|---|---|---|---|---|
| Capital Cost - $/kW | | | | | | |
| Power system | 232 | 230 | 208 | 190 | 345 | 280 |
| Gasification system | 111 | 107 | 117 | 99 | — | 111 |
| Fuel gas cleanup | 88 | 48 | 90 | 35 | — | 44 |
| Stack gas cleanup | — | — | — | — | 81 | — |
| Total capital cost | 431 | 385 | 415 | 324 | 426 | 435 |
| Owning-Plus-Operating Costs - mills/kWh | | | | | | |
| Owning cost[a] | 11.9 | 10.7 | 11.5 | 9.0 | 11.8 | 12.0 |
| Operation & maintenance | | | | | | |
| Power system | 1.3 | 1.3 | 1.2 | 1.1 | 1.1 | .8 |
| Gasification & cleanup | 2.8 | 2.1 | 2.8 | 1.8 | — | 2.5 |
| Stack gas cleanup | — | — | — | — | 1.1 | — |
| Fuel @ 60¢/MMBtu | 6.5 | 6.4 | 5.7 | 4.8 | 5.8 | 6.1 |
| Total power cost | 22.5 | 20.5 | 21.2 | 16.7 | 19.8 | 21.4 |

[a] Seventeen percent of capital, 70 percent load factor.

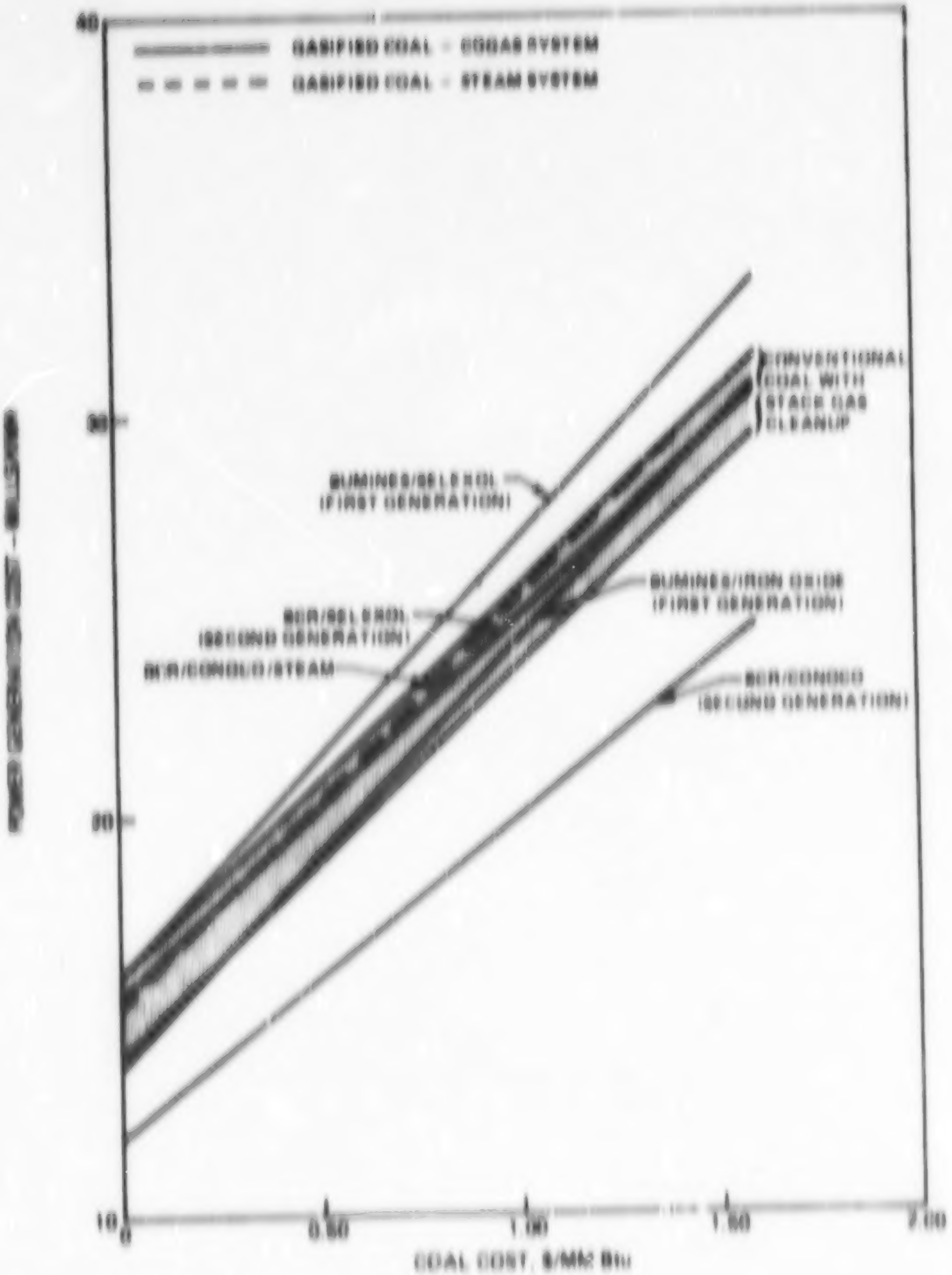

Figure 13. Cost summary.

Table 3. Estimated environmental impact of integrated gasification/combined-cycle power systems
(All values in lb/$10^6$ Btu coal unless otherwise noted)

| | Waste water | Thermal$^a$ | $SO_2$ | $NO_x$ | Particulate | Solids | Sulfur$^b$ | Ammonia$^b$ |
|---|---|---|---|---|---|---|---|---|
| BOM-Selexol | $219^c$ | $0.305_e$ | $0.320^f$ | $0.356_e$ | — | 14.6 | 2.96 | 1.38 |
| 2,200° F | $27^d$ | — | 0.088 | $0.174^g$ | $0.07^h$ | — | — | — |
| Total | 246 | 0.305 | 0.408 | 0.530 | 0.07 | 14.6 | 2.96 | 1.38 |
| BOM-Iron oxide | — | $0.378_e$ | $0.800^f$ | 0.31 | — | 14.6 | 2.51 | — |
| 2,200° F Comb.-cyc. | $27^d$ | — | 0.337 | $3.29^g$ | $0.06^i$ | — | — | — |
| Total | 27 | 0.378 | 1.137 | 3.70 | 0.06 | 14.6 | 2.51 | — |
| BCR-Selexol | $520^c$ | $0.376_e$ | $0.467^f$ | $0.300_e$ | — | 7.1 | 2.74 | 0.96 |
| 2,500° F comb.-cyc. | $24^d$ | — | 0.090 | $0.012^g$ | $0.07^h$ | — | — | — |
| Total | 544 | 0.376 | 0.557 | 0.312 | 0.07 | 7.1 | 2.74 | 0.96 |
| BCR-Conoco | $75^c$ | $0.302_e$ | 0.033 | — | — | 7.1 | 2.72 | — |
| 2,600° F comb.-cyc. | $22^d$ | — | 0.520 | $2.65^g$ | $0.04^i$ | — | — | — |
| Total | 97 | 0.302 | 0.553 | 2.65 | 0.04 | 7.1 | 2.72 | — |

[a] Millions of Btu rejected per million Btu of coal.

[b] Recovered with no credit for subsequent sale.

[c] Contains trace amounts of contaminants.

[d] Includes boiler makeup and cooling tower losses.

[e] Mechanical draft cooling towers are used.

[f] Includes emissions from Claus plant. A 90 percent + reduction could be obtained with tail-gas cleanup.

[g] Sum of thermal and fuel-related $NO_x$.

[h] Assumed to be equal to methane-fired systems.

[i] Sum of carryover and combustion products.

would pass directly through the high-temperature cleanup systems. $NO_x$ emissions from high-temperature systems would be higher than from low-temperature systems because of the fuel nitrogen and because hot fuel would produce higher combustion temperature leading to higher thermal $NO_x$. As indicated in table 3, emissions of $NO_x$ from power systems using hot cleanup processes could be unacceptable.

Both first and second generation systems will discharge substantial quantities of solid material for disposal to the environment. This solid material will be primarily ash and slag, with substantial amounts of chemical wastes (such as sodium sulfate or spent dolomite). Byproduct sulfur and ammonia can be stored in solid or liquid form until sold and should present no significant environmental problems.

The aqueous waste streams from the low-temperature cleanup systems are potentially hazardous. These streams will contain nonstrippable contaminants originally present in the raw fuel gas. Data on the nature and quantity of trace contaminants are not available. Design of a water treatment system to render the aqueous wastes acceptable for discharge would require detailed analysis for the specific gasification process involved.

## CONCLUDING REMARKS

The purpose of this paper has been to identify the economic, performance, and environmental characteristics of advanced combined-cycle power systems operating on distillate oil and coal-derived low-Btu gas. First generation coal gasifiers used in conjunction with commercially available low-temperature cleanup systems and combined cycles have the potential of producing electrical power at costs competitive with conventional steam plants using stack gas cleanup. These integrated gasification/combined-cycle systems would also have lower emissions of $SO_2$, $NO_x$, particulates, and reduced thermal pollution. High-temperature cleanup processes used in conjunction with advanced combined cycles have the potential of providing significant advances in efficiency and lower capital costs, resulting in power costs 20 percent lower than steam plants with stack gas cleanup. Emissions of $NO_x$ from systems using hot cleanup could be unacceptable.

Further work is underway to answer some of the questions that have been raised. For each of the system combinations, those factors that adversely affect either performance, cost, or pollutants have been identified and alternate approaches are being evaluated. In addition, other advanced gasification processes that would minimize the use of steam in the process and thus enhance the overall cycle are being considered. These efforts promise to show improved performance and cost characteristics while maintaining low levels of emissions.

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# GAS TURBINE HTGR FOR ECONOMICAL DRY COOLING OR HIGH-EFFICIENCY COMBINED CYCLE

John M. Krase[1]

## *Abstract*

*This paper describes the current reference design and the design evolution for a large, helium gas turbine nuclear power plant under development by General Atomic Company. This type of nuclear electric generating station offers major improvements in plant simplification, efficiency, resource utilization, and economics, as well as substantial reductions in the environmental effects of power generation. The dry-cooled reference design of the Gas Turbine HTGR (GT-HTGR) as of October 1977 is described. It includes a 3,000 MW High-Temperature Gas-Cooled Reactor (HTGR) and three power conversion loops, each containing a 370 MWe, horizontally oriented helium turbine-generator. Further studies in 1978 have established an improved design based upon the same concepts, which for a site with no cooling water would have a dry-cooled station efficiency of 40 percent. For sites with some cooling water, the reject heat from the helium turbine power conversion loops can be used in a wet-cooled secondary power cycle to produce additional power, thus raising the overall station efficiency to about 48 percent.*

## INTRODUCTION

The Gas Turbine High-Temperature Gas-Cooled Reactor (GT-HTGR) makes use of a helium-cooled graphite core to provide hot helium to a closed-cycle gas turbine power conversion system which operates on the reactor coolant helium. The helium gas turbines drive conventional electric generators to produce the electric output of the plant. The High-Temperature Gas-Cooled Reactor (HTGR) core, which is also used in the GT-HTGR, has been developed for commercial application in large central stations with a steam turbine-generator.

## BACKGROUND

### *Gas Turbines*

The closed-cycle gas turbine (ref. 1), including the helium turbine (ref. 2), has been developed primarily in Europe for use with fossil fuels (coal and coal gas). A number of small- to medium-size, fossil-fired, closed-cycle gas turbine plants for power generation, plus district heating are in service in Europe and Japan and have demonstrated very long life and high availability. The performance of this type of plant is particularly impressive since overall utilization of input heat in the form of electric power plus district heat can attain values of 60 to 80 percent. However, one of the critical components of the fossil-fired closed-cycle gas turbine has been the input heater which is limited in temperature level by materials and by combustion side corrosion and chemical effects. The availability of the HTGR core to provide the high-temperature gas (helium) for the closed-cycle gas turbine effectively solves the input heat exchanger problem which has limited the fossil-fired closed-cycle gas turbine to relatively small units where district heating is needed.

The open-cycle gas turbine development and utilization, in which the United States has been the leader, has has been strikingly successful in a wide variety of applications ranging from military and commercial aircraft, to vehicles, and to stationary application such as gas pipeline pumping, utility peaking generation, and intermediate load generation. The latter has made use of specially developed heavy-duty gas turbines with steam turbine bottoming cycles to achieve good availability and efficiency. Almost all of the open-cycle gas turbines so far have required relatively good quality petroleum-based fuels. Problems in long-term availability of such fuels are now seriously inhibiting further utility use of open-cycle gas turbine power plants. However, the technology and manufacturing capability needed for the helium gas turbines of the GT-HTGR already exist. In fact, the gas turbine temperature levels and other technical requirements for the GT-HTGR application are relatively easier than those of the fossil-fired gas turbines.

### *HTGR*

The first HTGR to produce electricity was the 40-MWe prototype built by General Atomic at Peach Bottom, Pennsylvania, which began commercial operation in June 1967. The Peach Bottom plant was shut down in October 1974 after a total of 1349 equivalent full-power days and producing more than 1.38 billion kWh of electric energy for the Philadelphia Electric Company. This reactor served as an invaluable test bed for the fuel for the large HTGR and for reactor physics studies. The average gross plant efficiency over its 7½-year life was 37.3 percent and the nuclear system availability was 88 percent, both of which are nuclear industry performance records.

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The 330-MWe Fort St. Vrain HTGR has been built by General Atomic for the Public Service Company of Colorado under the Power Reactor Demonstration Program of the U.S. Energy Research and Development Administration (ERDA).† Construction of the plant is complete, and power production is expected to start in 1976. The technology developed for the Fort St. Vrain plant and its main components is directly applicable to the large HTGR's scheduled for operation in the early 1980's. Development programs for these large reactors were initiated in early 1966; the remaining portions of these programs consist of component proof tests, continuing long-term metallurgical tests, and miscellaneous confirmatory tests of design details.

In addition to the HTGR programs in the United States (at General Atomic and Oak Ridge National Laboratory), extensive development programs are in progress in England (the DRAGON project), in Germany (the AVR and THTR plants and other advanced projects), in France (the commissariat à l'Energie Atomique), and in Japan.

### *HTGR Features*

The general arrangements of the large HTGR nuclear steam supply system are shown in figure 1. A schematic flow diagram is shown in figure 2.

The HTGR's use helium gas as the coolant, graphite as the neutron moderator and fuel-element structural material, with pyrolytic-carbon-silicon-carbide-coated $UC_2$ fissile fuel particles, and pyrolytic-carbon-coated $ThO_2$ fertile particles dispersed in a graphite matrix as the fuel.

The choice of graphite as the moderator and core structural material is based on its unique chemical, physical, and mechanical properties at elevated temperatures and on its very low neutron cross section, good radiation stability, ease of fabrication, and low cost.

The $Th/U^{233}$ standard fuel cycle (with $U^{235}$ as the initial fissionable fuel) is used because of its potential for achieving a higher fuel utilization and lower power cost than any other thermal spectrum reactor system. The neutronic characteristics of $U^{233}$ are superior to those of either plutonium or $U^{235}$ in thermal systems. A substantial portion of the energy comes from fission of the $U^{233}$ converted from the fertile $Th^{232}$. Efficient use of the thorium fuel cycle is of major significance in extending the U.S. nuclear fuel resources as indicated in figure 3. Features of the HTGR's uranium and thorium fuel cycle are summarized in figure 4.

Other features of the HTGR which apply also to the GT-HTGR include inherent safety resulting from the high-temperature capability and thermal capacity of the core which avoid the need for a fast-acting emergency cooling system, and the integration of the reactor and entire helium system into the PCRV. A very high integrity pressure vessel results from the use of multiple and redundant structural elements in the PCRV. The radioactive releases from the HTGR plant are negligible and very much lower than from LWR's.

### *GT-HTGR*

A program now in progress is aimed at the design and development of a commercial GT-HTGR power plant.

Because of its high reject-heat temperature the GT-HTGR is exceptionally well suited to economical rejection of waste heat directly to the air through the use of dry-cooling towers. For sites with cooling water a secondary power cycle can be added to generate substantially more power from otherwise reject heat, thereby increasing overall plant efficiency from an already high value of nearly 37 percent for a dry-cooled plant at ISO‡ standard day conditions, to about 46 percent for the water-cooled binary plant. The GT-HTGR plant designs described in this paper are based upon currently available technology and require a relatively low-cost design and development program.

Preliminary evaluations indicate that an 1,100-MWe dry-cooled GT-HTGR plant can be constructed for about the same cost as a wet-cooled conventional nuclear steam electric plant; and compared to a dry-cooled nuclear steam electric plant, the GT-HTGR plant exhibits a capital-cost advantage. With the wet-cooled binary-cycle GT-HTGR plant, an advantage in installed cost per kilowatt is expected relative to the dry-cooled GT-HTGR plant. In addition, there are fundamental advantages of further reduced reject heat from the plant and higher net plant output for a given thermal core power limit.

The preliminary design and program definition phase currently underway is a part of an overall program aimed at the design and development of the commercial GT-HTGR power plant. Both the dry-cooled and the wet-cooled binary-plant options are included. The conceptual and advanced preliminary design phases have involved substantial participation by the U.S. Energy Research and Development Administration, 16 utility companies, 3 leading turbomachinery manufacturers, and the General Atomic Company. A prominent feature of the proposed development program for the GT-HTGR

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†Formerly the U.S. Atomic Energy Commission.

‡International Standards Organization (ISO) sea-level standard atmospheric temperature of 59° F.

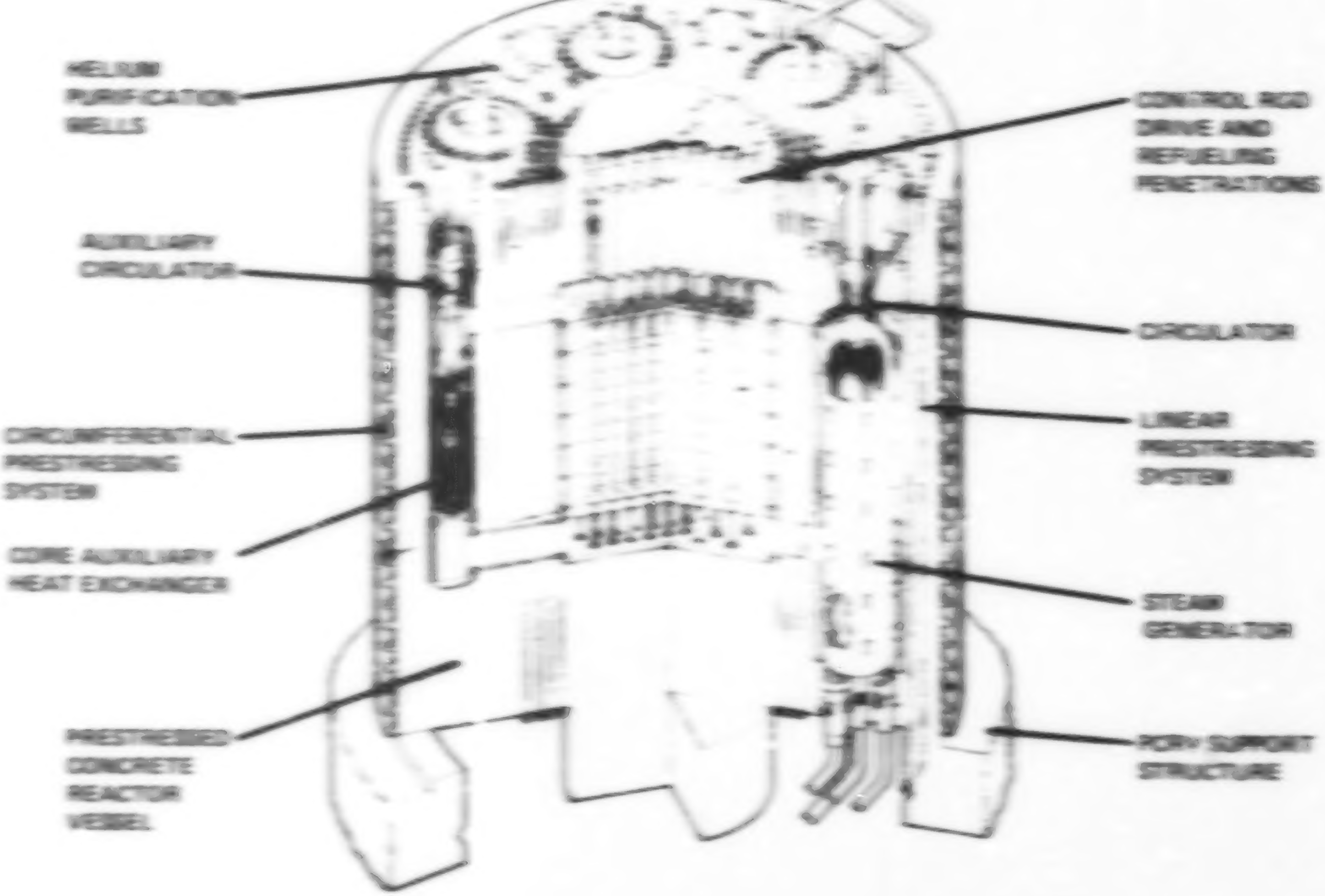
HELIUM PURIFICATION WELLS
CONTROL ROD DRIVE AND REFUELING PENETRATIONS
AUXILIARY CIRCULATOR
CIRCULATOR
CIRCUMFERENTIAL PRESTRESSING SYSTEM
LINEAR PRESTRESSING SYSTEM
CORE AUXILIARY HEAT EXCHANGER
STEAM GENERATOR
PRESTRESSED CONCRETE REACTOR VESSEL
PCRV SUPPORT STRUCTURE

Figure 1. HTGR nuclear steam system.

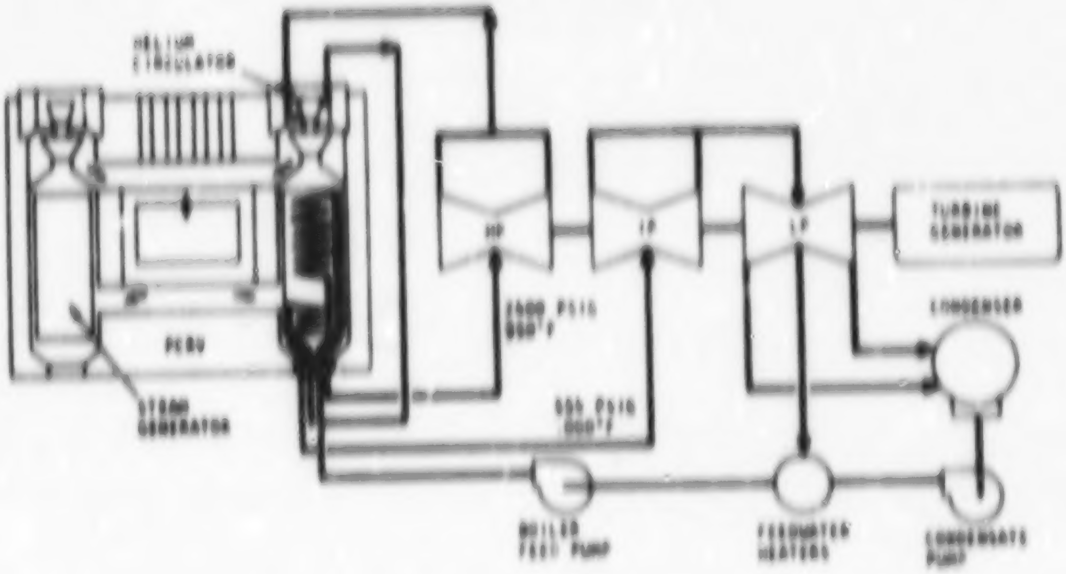
HELIUM CIRCULATOR
PCRV
STEAM GENERATOR
HP
IP
LP
TURBINE GENERATOR
CONDENSER
2500 PSIG
555 PSIG
BOILER FEED PUMP
FEEDWATER HEATERS
CONDENSATE PUMP

Figure 2. Overall HTGR plant flow diagram of typical secondary cooling system.

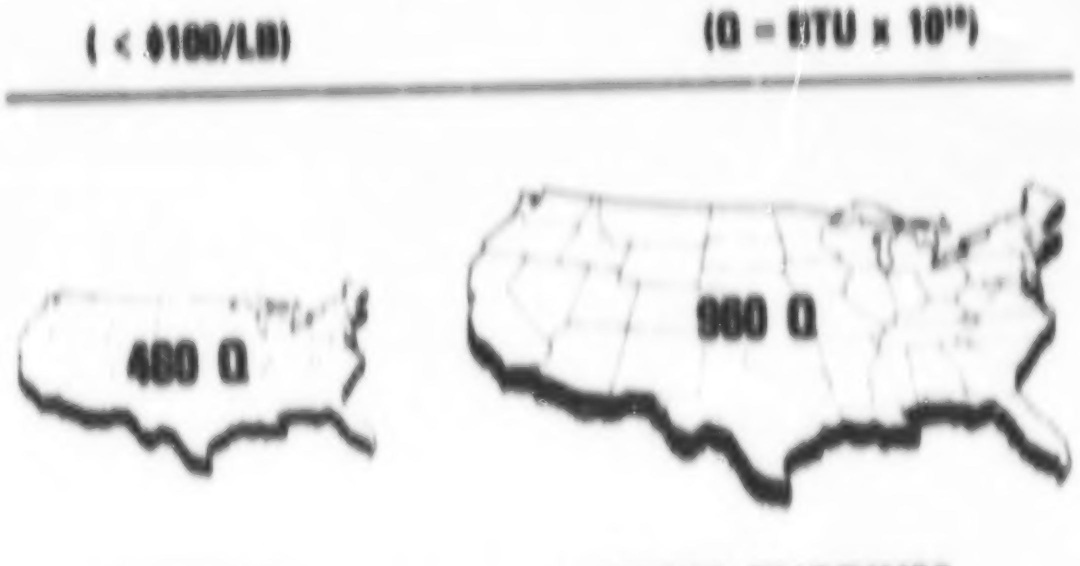

Figure 3. Probable U.S. uranium and thorium resources.

**URANIUM/THORIUM FUEL**

- **HIGH CONVERSION RATIO**
- **HIGH BURNUP**
- **LOWER FUEL INVENTORIES**
- **REDUCED SENSITIVITY TO CHANGING $U_3O_8$ COSTS**

Figure 4. Uranium/thorium fuel.

is the full-scale demonstration test of a 370-MWe gas turbine-generator and other primary system components in a fossil-fired test facility. A preliminary engineering study of the facility by NASA is currently in progress under ERDA sponsorship.

Also, a program is in progress in the Federal Republic of Germany for the development of a direct-cycle nuclear gas turbine plant designated as HHT. As a result of a joint investigation in 1974 between the General Atomic Company and Hochtemperatur Reaktorbau GmbH (HRB) of Germany, the reactor designer and systems integrator for the German direct-cycle project, a substantial degree of commonality in plant configuration was developed. Similarity in plant configuration and coordination of development efforts is expected to benefit both programs.

## GAS TURBINE HTGR

*Cycle Conditions*

The reference-plant cycle, figure 5, is dry cooled. The binary-plant cycle conditions are shown in figure 6. The cycle conditions are given for 80° F cooling-water temperature.

The resulting net plant performances with a 3,000-MWt reactor core are 37 percent efficiency—about 1,100 MWe for the dry-cooled plant, and 40 percent efficiency—about 1,200 MWe for the binary plant. Major design point and rated parameters for the dry-cooled plant are given in table 1. The more important parameters remain much the same since plant conception, consistent with the goal of maximizing the use of existing technology.

1. 1,000-psi maximum design-point primary-system pressure results in high gas density and compact turbomachinery with only a modest extension of PCRV structural technology. Preliminary studies indicate this is the economical choice as well.
2. 1,500° F turbine inlet temperature is achieved with the same peak fuel temperature used by current steam-cycle HTGR's. Also, this is below the temperature level where turbine-blade cooling is required.
3. The design-point compressor compression ratio of 2.35 is slightly less than optimum for efficiency, but it was chosen to reduce the number of turbine and compressor stages needed.

*Dry Cooled Plant Description*

The GT-HTGR reference-plant design has an integrated primary loop with all primary system components including the turbomachinery contained within the PCRV. A closed-loop circulating-water system carries reject heat from the primary power conversion loops to two natural-draft dry-cooling towers where it is dissipated to the atmosphere. The capability for economic dry cooling is considered a major advantage of this type of plant.

The compact, integrated-circuit gas turbine power plant provides inherently high reliability against pressure-boundary failures that could result in rapid system depressurization. This important safety feature has been basic to the circuit design since early conceptual studies.

*Plant Arrangement*

Major components of the primary system are illustrated in figure 7. The 3,000-MWt reactor system incorporates three power conversion loops. Each loop includes a single-shaft gas turbine and generator of 370-MWe rating, a recuperative heat-exchanger unit, and a precooler heat exchanger for cycle-heat rejection. The heat exchangers are contained in vertical cavities arranged within the PCRV wall, two for each loop. The three turbomachines and generators are horizontally

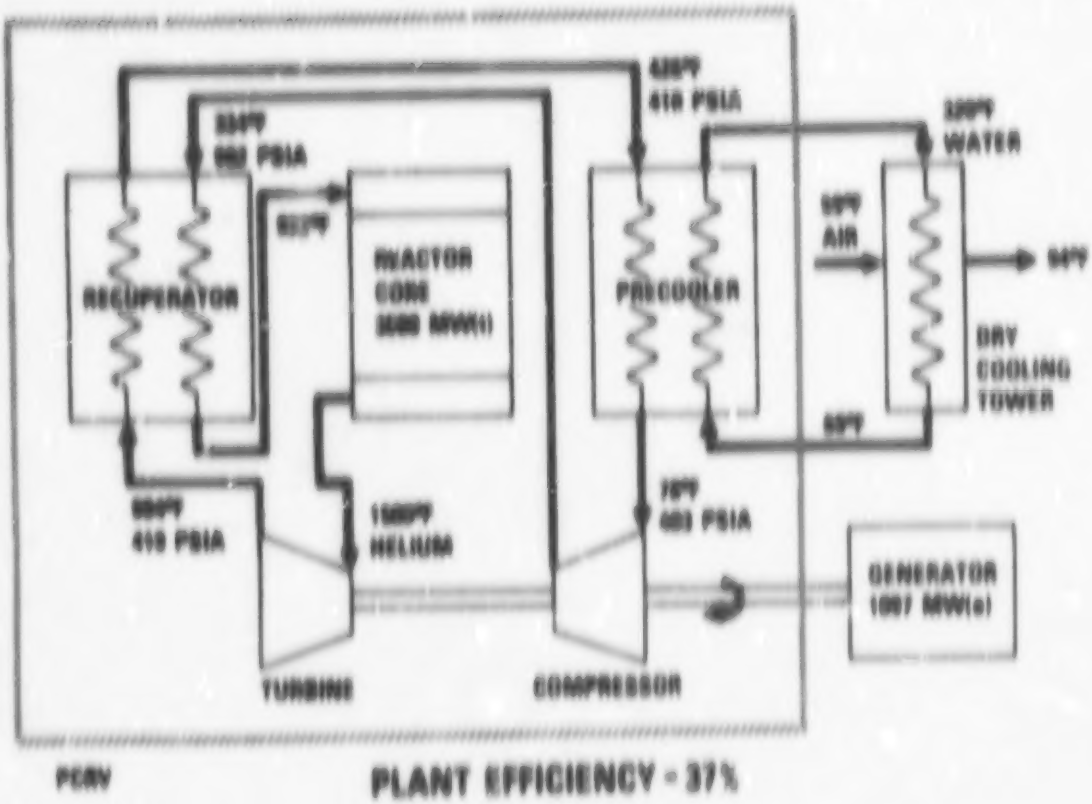

Figure 5. GT-HTGR with dry cooling

oriented and spaced azimuthally 120 degrees apart. The generators are external to the PCRV, and the turbomachines are within the radial PCRV cavities. The connecting output shaft penetrates through the PCRV closure plug. Purified-helium buffer seals on the shaft assure no leakage of primary helium at the shaft penetration. Horizontal orientation allows use of a conventional generator and employs a more conventional turbomachine. Penetrations in the bottom head of the PCRV make in situ access to the turbomachinery bearings possible. This is a particular advantage of the horizontal arrangement.

The secondary containment vessel is a prestressed cylindrical concrete structure of 150-ft inside diameter with an oblate spheroidal dome. The generators are housed in grade-level enclosures that extend radially about 40 ft from the containment cylinder wall.

Heat rejection is accomplished by the recirculating water system and dry-cooling towers. Also included in balance-of-plant are the reactor service building (including fuel storage and shipping), service systems, auxiliaries, and maintenance facilities.

*Reactor*

The fuel components, reactor core and reflectors, core support, control rod mechanisms, and fuel-handling equipment for the GT-HTGR plant are essentially the same as those used for the commercially offered steam-turbine HTGR. Modest core loading adjustments are anticipated to account for the approximately 40 percent higher helium flow rate and correspondingly lower coolant temperature rise in the GT-HTGR application. With 1,500° F reactor outlet temperature, the peak fuel and graphite temperatures in the core are essentially the same as those in the steam plant. The lower reactor outlet temperature in the 3,000-MW(t) steam-turbine HTGR of 1,366° F is offset by the lower helium temperature rise in the hot channel of the gas turbine reactor core because of the higher helium flow rate, thereby retaining the same maximum fuel-temperature conditions.

*Components*

A significant advantage of the closed-cycle gas turbine is that the compact size of the turbomachinery

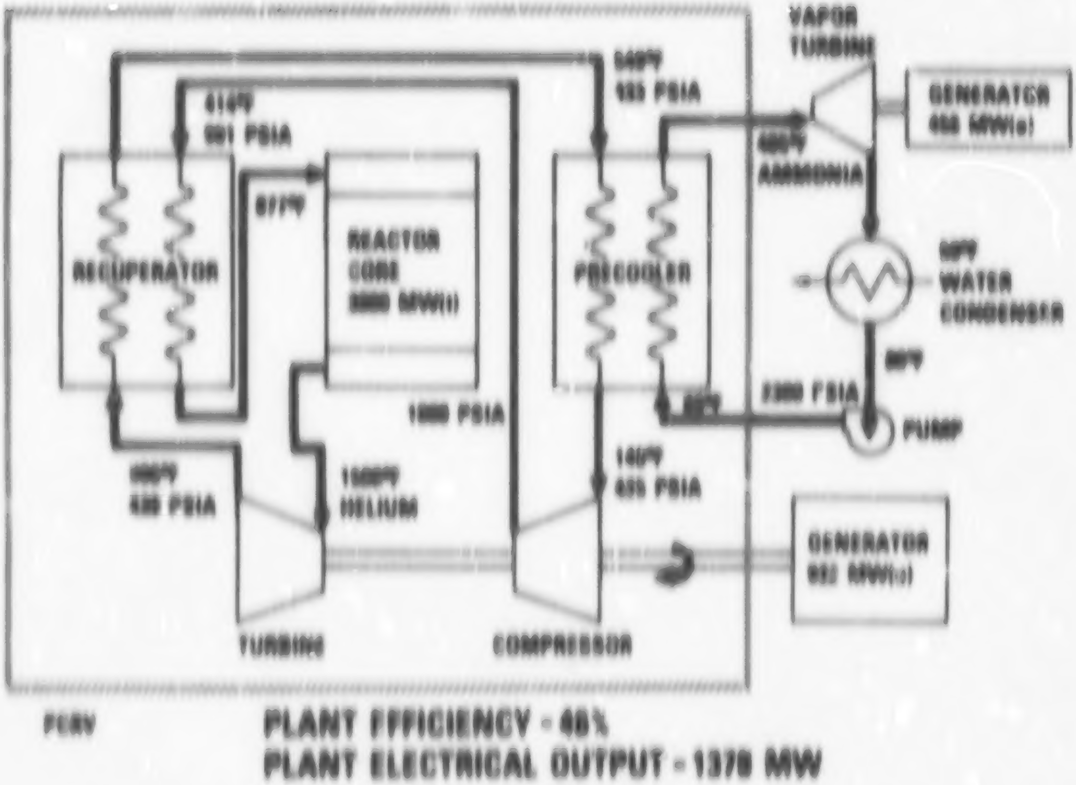

Figure 8. Binary GT-HTGR with wet cooling

allows design of a completely integrated circuit with its attendant safety and economic benefits. Figure 8 illustrates the configuration of a 370-MWe axial-flow turbomachine. Dimensions of the unit are similar to those of heavy-duty open-cycle gas turbine units of the 50- to 100-MWe range currently in utility generating service.

To achieve high cycle efficiency, the heat exchangers for the closed-cycle GT-HTGR require significantly greater total heat-transfer surface area than, for comparison, the steam generators in a steam-turbine plant of the same output rating. However, tube sizes are smaller and the requirements are substantially less demanding in key structural areas for the gas turbine plant heat exchangers.

The recuperator experiences maximum shell-side gas temperature of a little over 1,000° F with a maximum tube-wall pressure difference of about 574 psi under normal conditions. Minor leaks between the two helium streams do not constitute a serious problem but result only in some performance degradation, depending on the quantity of leakage relative to the total loop flow.

In the precooler the temperatures are even lower, with a normal maximum gas inlet temperature in the range of 400° F for the dry-cooled plant. Pressure difference is only about 100 psi, with the highest pressure on the helium shell side. Thus, a leak would result in helium flowing into the cooling-water loop rather than water leakage into the reactor. This can be readily detected and promptly isolated.

*Heat Rejection System*

A key feature of the GT-HTGR plant is its adaptability to economic dry cooling. The elimination of water consumption requirements for primary cooling will greatly increase potential plant siting options in many areas, without otherwise attendant economic penalties.

Two natural-draft dry towers are used for the preliminary dry-cooled 1,100-MWe plant design. Design studies suggest tower dimensions of about 300-ft base diameter decreasing to a 200-ft top-section diameter

Table 1. Gas turbine HTGR performance
at design point and rating point

| | Design point | ISO rating point |
|---|---|---|
| Ambient temperature, °F | 75 | 59 |
| Reactor inlet temperature, °F | 934 | 922 |
| Reactor outlet temperature, °F | 1500 | 1500 |
| Reactor flow rate, lb/hr | 14,505,000 | 14,199,000 |
| Reactor power, MWt | 3000 | 3000 |
| Compressor outlet temperature, °F | 349 | 334 |
| Compressor inlet temperature, °F | 95 | 78 |
| Compressor flow rate, lb/hr | 5,015,000 | 4,909,000 |
| Compressor pressure ratio | 2.35 | 2.41 |
| Compressor outlet pressure, psia | 1000 | 971 |
| Turbine inlet temperature, °F | 1500 | 1500 |
| Turbine outlet temperature, °F | 1018 | 994 |
| Turbine flow rate, lb/hr | 4,915,000 | 4,811,000 |
| Turbine pressure ratio | 2.129 | 2.178 |
| Net electrical output, MW | 1069 | 1097 |
| Power plant efficiency, percent | 35.62 | 36.57 |

above the heat-exchange modules, and an overall height of 953 ft. With selection of mechanical-draft cooling, the dimensions would, of course, be greatly reduced. These towers are substantially smaller and of less cost than would be required for a steam-turbine plant. Smaller towers can be used because the higher water inlet temperature results in a large air temperature rise which reduces the air flow requirements. The hotter air induces greater buoyancy and thereby higher air flow velocities for a given height. Also, further economies can be achieved in the heat-exchanger modules by using multiple passes with the large water temperature drop available.

Although there is little experience in the United States with large natural-draft dry-cooling towers, there is extensive process-industry experience with mechanical-draft dry-cooling systems and, in addition, experience at a 20-MWe power station at Gillette, Wyoming. Also at Gillette, the 330-MWe WYODAK coal-fired station is under construction for 1977 operation. It will also incorporate a direct mechanical-draft air-cooled condenser system. An ERDA-sponsored dry-cooling-module test program is planned for the WYODAK station.

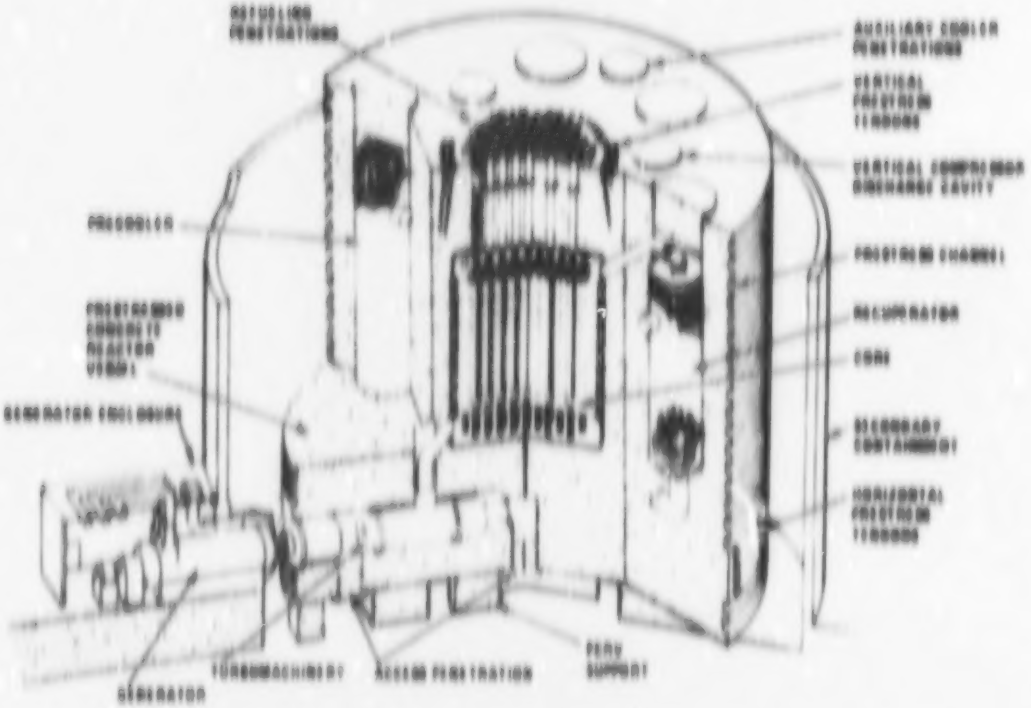
REFUELING PENETRATIONS
AUXILIARY COOLER PENETRATIONS
VERTICAL PRESTRESS TENDONS
VERTICAL COMPRESSOR DISCHARGE CAVITY
PRECOOLER
PRESTRESS CHANNEL
PRESTRESSED CONCRETE REACTOR VESSEL
RECUPERATOR
CORE
GENERATOR ENCLOSURE
SECONDARY CONTAINMENT
HORIZONTAL PRESTRESS TENDONS
CORE SUPPORT
TURBOMACHINERY
ACCESS PENETRATION
GENERATOR

Figure 7. Three-loop 3,000-MW GT-HTGR power plant.

In Europe, a number of large natural-draft dry towers for electrical generating plants up to 220 MW are in service, dating to 1962 in the case of the 120-MWe generating station in Rugeley, England. A natural-draft dry tower is currently under construction for the 300-MWe THTR reactor at Schmehausen, a West German high-temperature reactor that closely parallels the General Atomic Company's 330-MWe Fort St. Vrain HTGR.

## BINARY PLANT DESIGN

*System Design*

The ammonia balance of plant systems are similar to a steam power plant in their functional design requirements. Vapor systems include a main vapor circuit, a vapor bypass circuit, and a feedpump turbine circuit. The condensate system includes a main condensate feed circuit, a condensate bypass line, a condensate storage and makeup system, auxiliary services, and a precooler isolation and dump system.

The main vapor circuit transports supercritical ammonia from the precooler to the secondary turbine and condensers. Piping from the three precoolers is joined into a single inlet line to the turbine. Temperatures are controlled by regulating inlet flow to the precoolers. Turbine stop and bypass valves are provided as in most steam plant to control power. Vapor flows from the double flow turbine to twin condensers beneath the turbine. The slightly superheated vapor must be desuperheated in the turbine exhaust.

## CONCLUSIONS

The dry-cooled GT-HTGR plant offers the means whereby power plant siting flexibility can be substantially increased without efficiency penalty or cost disadvantage. With other advantages of the basic HTGR, the result is a nearly environmentally neutral plant. Optionally, the binary-cycle GT-HTGR maximizes electrical output from available cooling water and nuclear fuel resources because of the very high efficiency achievable by combining the closed-cycle gas turbine with a vapor secondary power cycle. For either option, the resulting power plant offers the highest available nuclear efficiencies with lower generating costs and with minimum

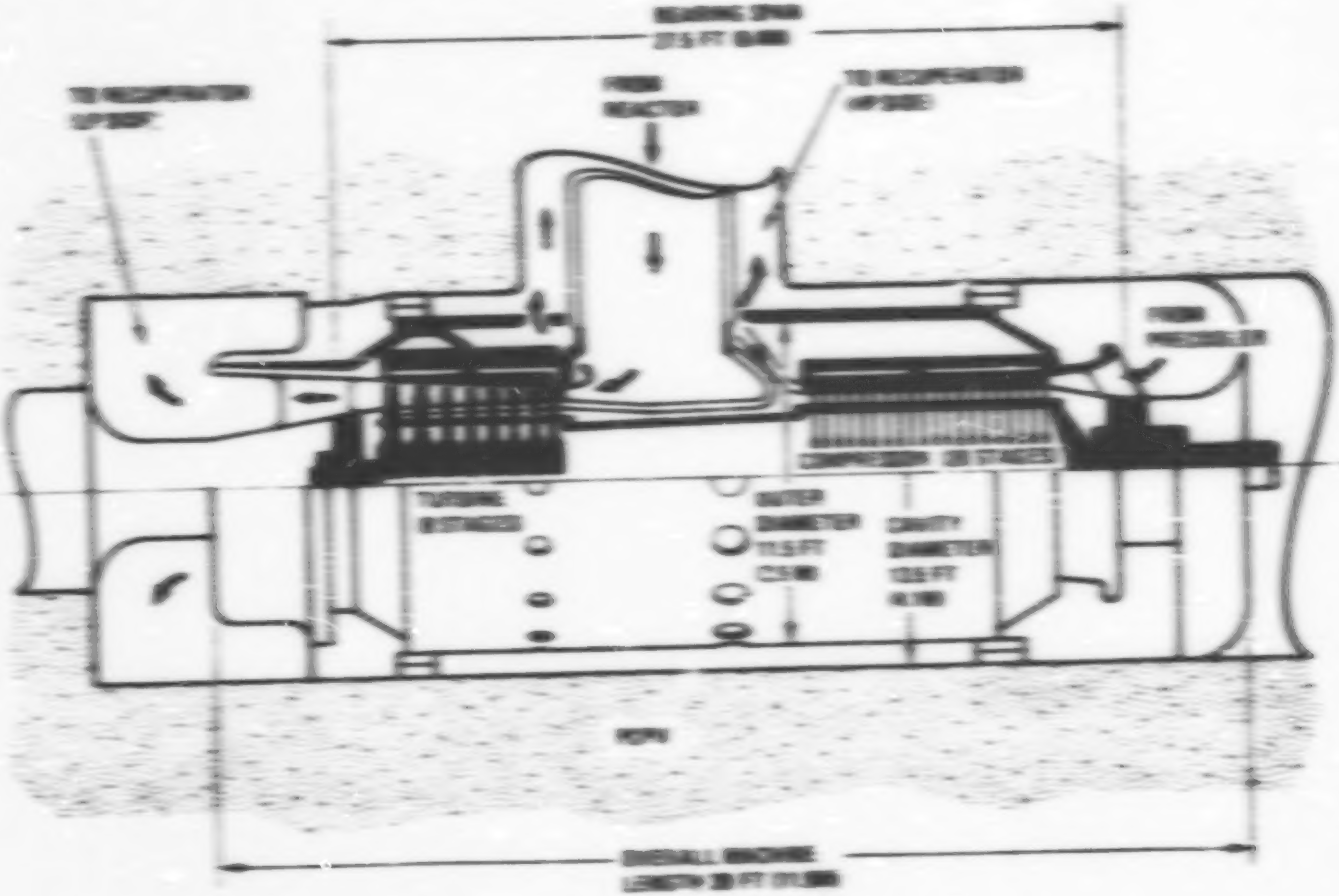
BEARING SPAN
27.5 FT (8.4M)
TO RECUPERATOR
(LP SIDE)
FROM
REACTOR
TO RECUPERATOR
(HP SIDE)
FROM
PRECOOLER
COMPRESSOR 20 STAGES
TURBINE
8 STAGES
OUTER
DIAMETER
11.5 FT
(3.5 M)
CAVITY
DIAMETER
13.5 FT
(4.1M)
PCRV
OVERALL MACHINE
LENGTH 39 FT (11.9M)

Figure 8. Three hundred and seventy-MWe GT-HTGR turbomachine.

Table 2. Performance and growth of GT-HTGR

| | GT-HTGR Mark I (1,500° F) | | GT-HTGR Mark II (1,600° F) | |
|---|---|---|---|---|
| | Dry-cooled | Binary cycle | Dry-cooled | Binary cycle |
| Station efficiency, % | 36.6 | 45.3 | 42 | 50 |
| Output from three-loop system, MWe | 1,100 | 1,360 | 1,400 | 1,730 |
| Output from four-loop system, MWe | 1,470 | 1,810 | 1,860 | 2,300 |
| Reject heat relative to LWR | 0.71 | 0.58 | 0.57 | 0.48 |

environmental impact. Moreover, with the relatively near-term potential for increased temperature, considerable increases in efficiency are realized as shown on table 2, both for the dry-cooled and binary-cycle plant versions.

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# ENVIRONMENTAL AND SAFETY CONSIDERATIONS FOR A FOSSIL FUEL-FIRED POTASSIUM-STEAM BINARY VAPOR CYCLE[*]

A. P. Fraas[†] and Robert S. Holcomb[‡]

## *Abstract*

*Design studies indicate that superimposing a potassium vapor cycle on a conventional steam cycle should increase the thermal efficiency of a fossil fuel-fired plant to about 50 percent, thus reducing the fuel consumption by about 25 percent, and the rejection of waste heat to the environment by about 33 percent. Systems have been designed for burning gas or oil in furnaces that would employ burners that recirculate flue gases to reduce $NO_x$ release. High sulfur coal would be burned in a fluidized bed furnace fed with limestone or dolomite to react with the $SO_2$ in the combustion zone and reduce the emission of $SO_2$ by about 90 percent. Electrostatic precipitators operating at a flue gas temperature of about 800° F (427° C) could be used to control the emission of particulates to a very low level.*

*The reactive character of potassium dictates that careful attention be given to the design and construction of the system to insure that the safety of the plant is maintained. A novel design for the potassium condenser-steam generator has been evolved to minimize the energy release of a steam leak into the potassium. By employing this design along with the high standards of fabrication and the sensitive leak detection methods that have been developed for liquid metal systems in the nuclear power program, the probability of serious consequences from a leak should be kept very low. The worst accident from the standpoint of the public would be the release of most of the potassium inventory to the stack. Such an accident is unlikely since the combustion gas pressure in the furnace would be higher or nearly equal to the potassium pressure in the boiler. To guard against this contingency, a wet scrubber would be included at the base of the stack so that it could be activated in an emergency.*

## INTRODUCTION

For over half a century, up to 1950, the electric power industry continually improved its new steam plants to give a higher thermal efficiency. In nearly a quarter of a century since 1950 there has been essentially no further improvement. In searching for a new approach that would give a much higher thermal efficiency for power plants of the future, A. P. Fraas proposed in 1966 that a potassium vapor topping cycle be superimposed on a conventional steam cycle (ref. 1). This approach would yield a substantially higher overall thermal efficiency for a given peak cycle temperature than can be obtained with a Brayton cycle because of the inherently higher efficiency of a Rankine cycle. Further, by using potassium in the high-temperature topping cycle, it is possible to avoid the high pressures and corrosivity of steam in systems designed for operation in the temperature range above 1,000° F (538° C). Studies indicate that this yields an unusually attractive power plant for use with fossil, fission, and fusion heat sources, and presents relatively tractable development problems when compared with other advanced cycle systems.

Potassium is a soft metal; at room temperature it is about the texture of hard butter. It melts at 144° F (62° C) and boils at 1,400° F (760° C) at atmospheric pressure. At 1,540° F (838° C), the turbine inlet temperature currently projected, the pressure would be only 15 psi (1.0546 kg/cm²) above atmospheric pressure, and the vapor density and other properties affecting the design of the turbine would be about the same as for steam at 240° F (116° C). After expanding the potassium vapor through a turbine, it would be condensed at about the same pressure and density as currently used in steam turbines, but the temperature would be about 1,100° F (593° C). The heat rejected from the potassium vapor cycle would then be used to raise steam at around 1,000° F (538° C). By following this approach it should be possible to obtain a thermal efficiency of about 50 percent from the combined potassium-steam binary vapor cycle. When compared with conventional steam plants this would reduce the fuel consumption by about 25 percent and would reduce the waste heat rejection to rivers, lakes, or cooling towers by about 33 percent.

Critical studies of this cycle indicate that it is theoretically sound (refs. 1-5). The big question is whether a

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practical, dependable system can be obtained at a reasonable capital cost. Major elements in any such evaluation are the safety and environmental problems that will be raised by an unorthodox system of this sort employing an alkali metal as a working fluid. Fortunately, an extensive background of experience has been obtained with alkali metal systems under the atomic energy program, and over 200,000 hr of boiling potassium system operation was obtained under the space power plant program (ref. 6). This experience coupled with extensive experience with mercury in the same laboratories indicates that a potassium vapor system should present substantially less difficult operational and safety problems than a mercury vapor system, and several mercury vapor topping cycle plants were successfully operated in the United States in the period from 1920 to 1970 (refs. 7,8). (The mercury vapor topping cycle was dropped by U.S. utilities in part because its upper temperature limit proved to be 900° F (482° C) as compared to over 1,000° F (538° C) for steam, thus giving steam an edge in thermal efficiency, and in part because the price of mercury rose to the point where the capital investment became excessive.)

This paper presents an evaluation of the environmental pollution control and safety problems of gas-, oil-, and coal-fired potassium vapor topping cycle systems. The material in this paper is based to a large extent on a more thorough treatment of these problems given in reference 9.

## SYSTEM DESCRIPTION

Conceptual designs have been made for gas- or oil-fired systems (refs. 2,10) and for fluidized-bed coal combustion systems (ref. 11).

### *Gas- or Oil-Fired System*

The basic layout of the system envisioned is shown in figure 1. Three basic systems are coupled to form the

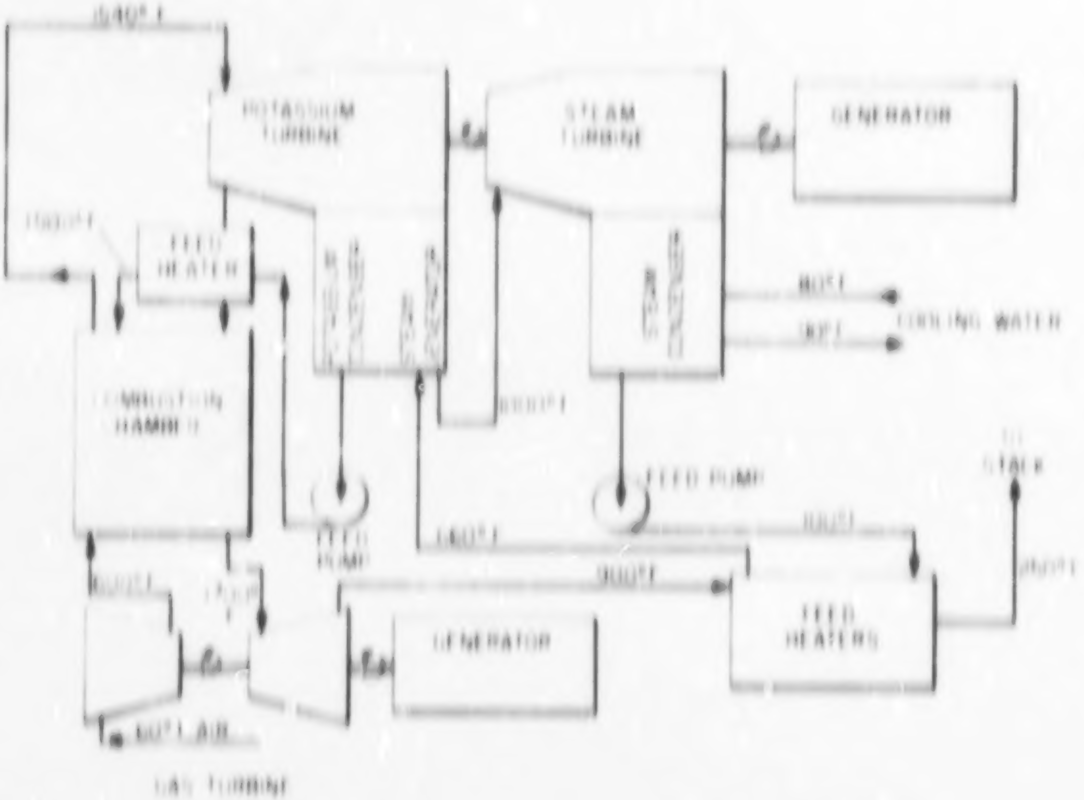

Figure 1. Flow sheet for the proposed gas or oil fired potassium vapor topping cycle.

power plant, i.e., a gas turbine that supercharges the combustion chamber for the potassium boiler, the potassium vapor topping cycle, and an essentially standard steam cycle. For purposes of this paper, the most important components are the furnace-potassium boiler unit and the potassium condenser-steam generator unit, both of which employ tube bundle modules as their basic unit of construction.

*Potassium Boiler*

As can be seen in figure 2, the potassium boiler tube bundle module consists of two annular rows of 1 in. (25.4 mm) diameter stainless steel tubes arranged around a 23 in. (584.2 mm) diameter, long, vertical, cylindrical combustion chamber. The tubes are bent at the top to provide flow passages between them so that the hot gas from the top of the combustion chamber can flow radially outward and then downward through an outer annulus over the outer row of tubes. To reduce the amount of heat transfer surface area required, the furnace and combustion chambers would be operated at a pressure of 5 to 10 atm, i.e., substantially above the 2 atm which would be the design operating pressure of the potassium vapor system. Potassium would circulate by thermal convection from a header tank at the top of the tube bundle through downcomers to ring-shaped manifolds at the bottom, and then vertically upward through the tubes back to a header drum and vapor separator at the top of the header tank. Around 200 tube bundles of this type would be required in a 600 MWe power plant.

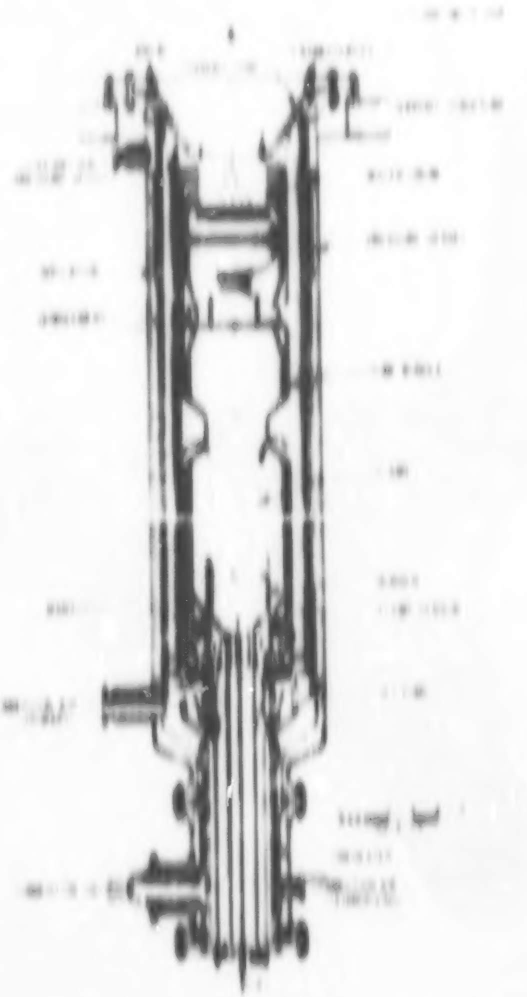

Figure 2. Section through the full scale potassium boiler tube bundle and burner module being developed at ORNL under the NSF/RANN program. The unit is shown installed in a special casing for test purposes.

*Furnace*

The boiler tube bundles would be mounted in four to eight furnace shells in the form shown in figure 3. In this layout the burner assemblies are independently mounted in the bottom head of the furnace shell with individual flanges so that any burner can be removed without disturbing the others. The boiler tube bundles are also independently mounted to a grid at the top, which in effect serves as the top head. The design is such that any tube bundle can be replaced independently of the others by disconnecting it and withdrawing it through either the top or the bottom of the furnace.

*Potassium Vapor Turbine*

The potassium turbine of figure 4 would be essentially similar to a low-pressure steam turbine except that more elaborate shaft seals would be required. These shaft seals would employ a three-stage labyrinth seal between two face seals as in figure 5. In the labyrinth seal, argon buffer gas would be admitted to the center stage and bled from the two bleedoff regions between the three stages, one bleed consisting of air plus argon and one consisting of argon plus potassium vapor.

*Potassium Condenser-Steam Generator*

The potassium condenser-steam generator unit would be mounted directly beneath the potassium vapor turbine in much the same fashion as steam condensers are mounted under steam turbines (fig. 4). The steam generator tubes would be of the reentry type indicated in figure 6 with feedwater admitted to the bottom of a central tube about 1/4 in. (6.35 mm) in diameter in which it would boil as it rose to the top of the tube (ref. 12). The steam emerging from the top of the inner tube

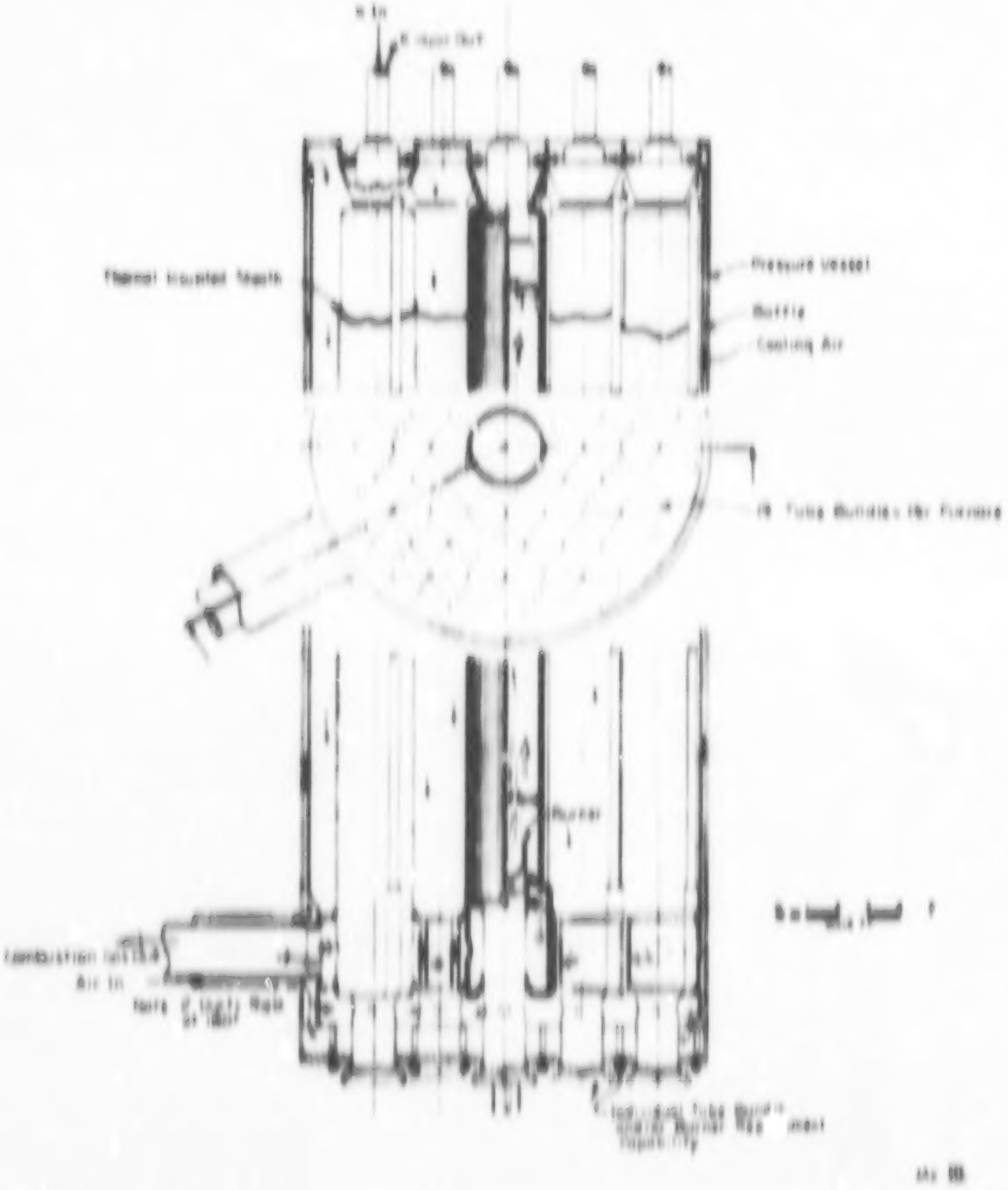
K In
K Vapor Out
Thermal Insulated Sheath
Pressure Vessel
Baffle
Cooling Air
19 Tube Bundles for Furnace
Burner
Combustion
Air In

Figure 3. Section through a furnace-potassium boiler unit showing provisions for the burner installation at the bottom and the boiler tube bundle mounting arrangement at the top.

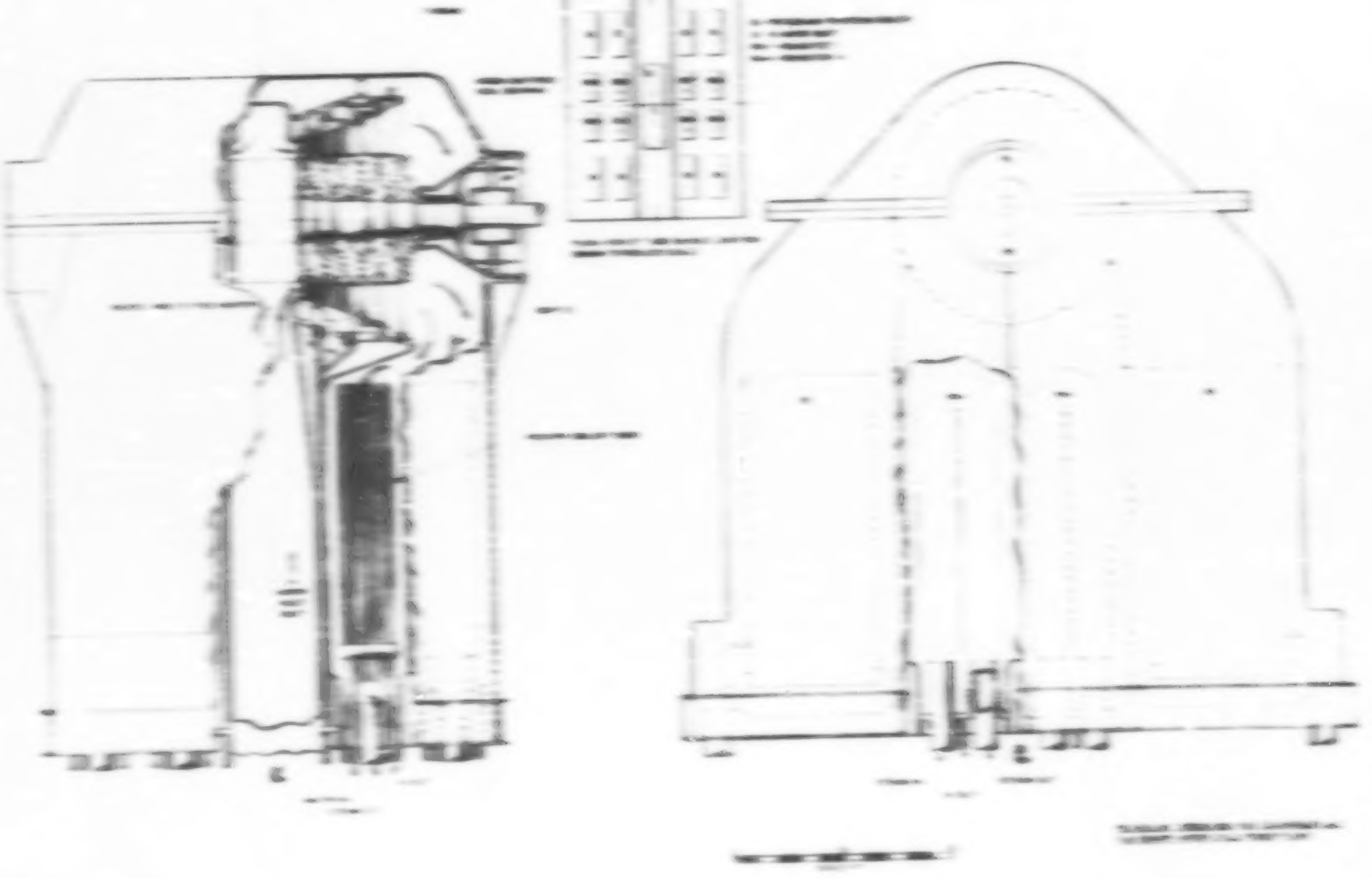

Figure 4. Potassium vapor turbine, condenser, and steam generator for the reference design.

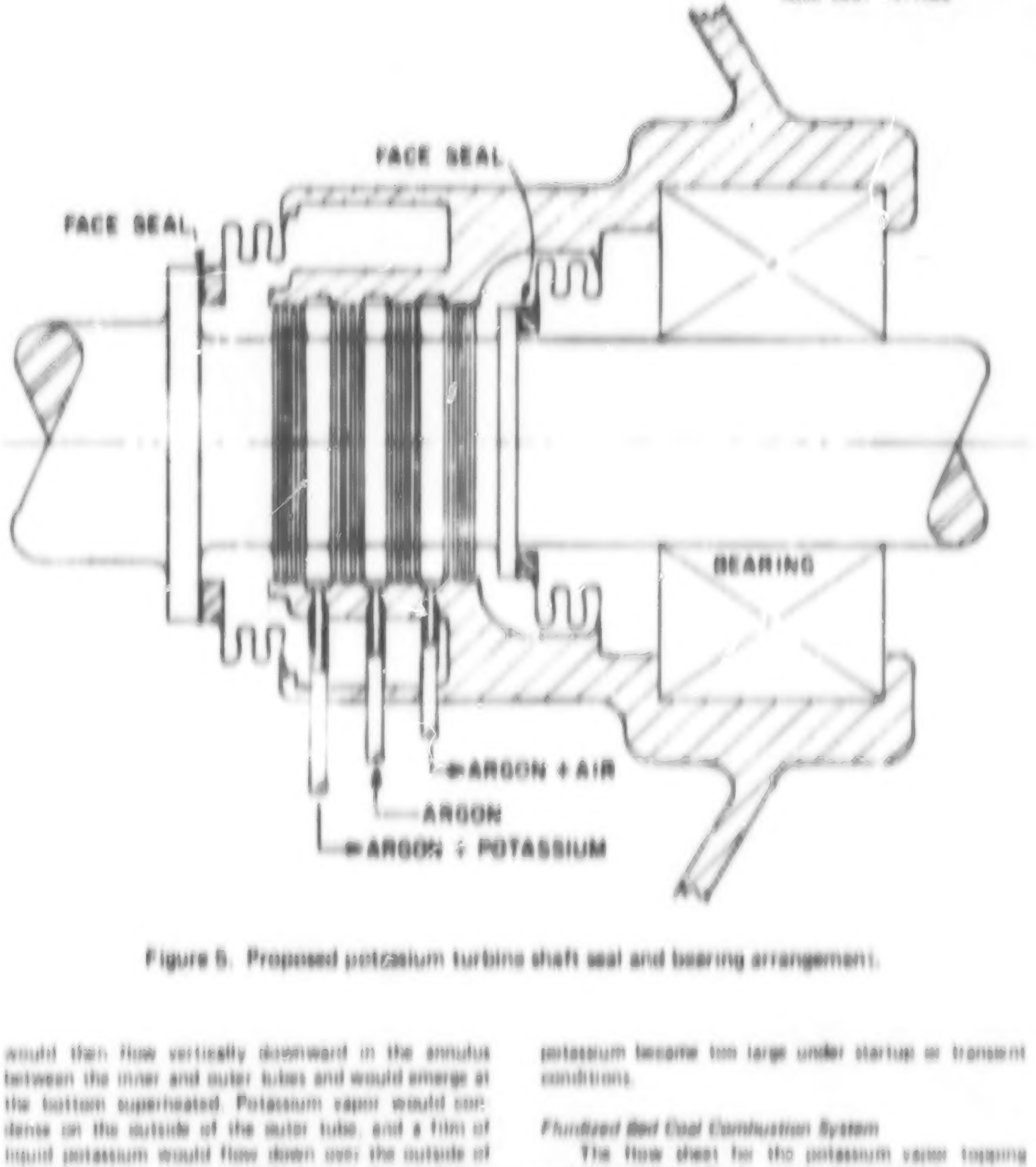

Figure 5. Proposed potassium turbine shaft seal and bearing arrangement.

would then flow vertically downward in the annulus between the inner and outer tubes and would emerge at the bottom superheated. Potassium vapor would condense on the outside of the outer tube, and a film of liquid potassium would flow down over the outside of the outer tube to the sump at the base of the condenser. The reentrant tube design was devised to avoid large thermal stresses that might be induced by the high heat transfer coefficients inherent in the boiling of water and condensing of potassium if these processes took place on opposite sides of a single tube wall if the temperature difference between the boiling water and the condensing potassium became too large under startup or transient conditions.

### *Fluidized Bed Coal Combustion System*

The flow sheet for the potassium vapor topping cycle coupled to a fluidized bed coal combustion system is shown in figure 7. The arrangement is similar to that for the oil-fired furnace. The major difference is that clean combustion air instead of flue gas air is used to drive the gas turbine. The air is compressed to about 110 psia (7.733 kg/cm²), heated to 1,500° F (816° C) in the economizer, and then sent through the gas turbine. It

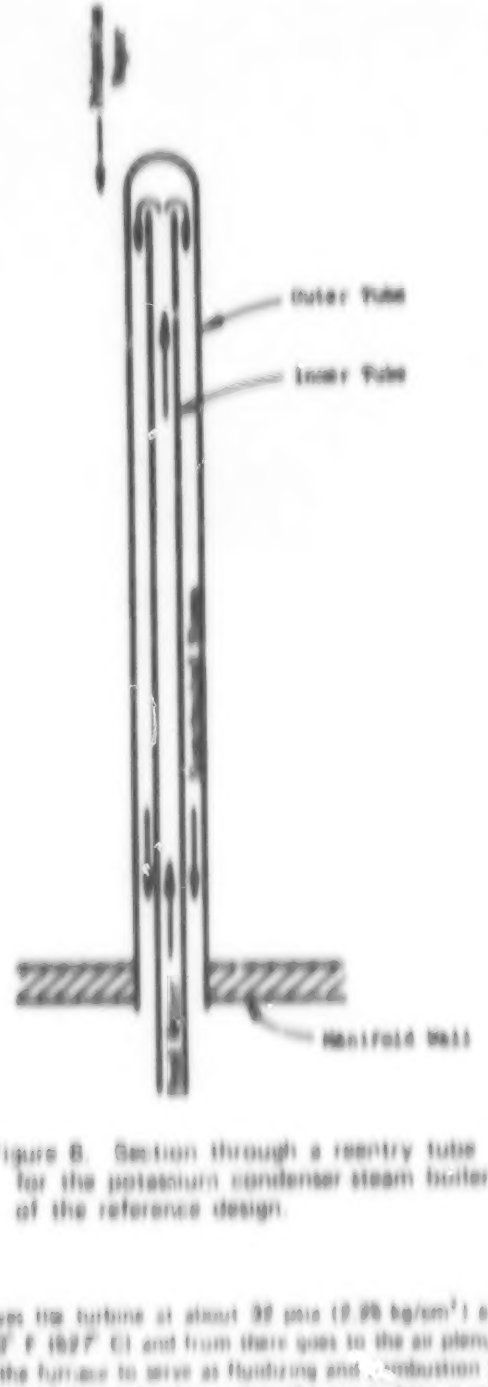

Figure 8. Section through a reentry tube for the potassium condenser steam boiler of the reference design.

leaves the turbine at about 32 psia (2.25 kg/cm²) and 1160° F (627° C) and from there goes to the air plenum of the furnace to serve as fluidizing and combustion air for the furnace. In this system the gas turbine is used only to provide power for raising the combustion air pressure high enough to make up the pressure drop across the air distributor and fluidized bed, and no gas turbine is used to generate electric power. This arrangement has the advantage that there are no problems with turbine blade erosion or deposits, as might be the case if flue gas were used to drive the gas turbine. The combined-cycle efficiency for this system is ~50 percent, the same as that for the gas-fired plant.

*Potassium Boiler*

The conceptual design for a potassium boiler heated by a fluidized-bed furnace is shown in figure 9. The potassium boiler tubes would be about 1 in. (25.4 mm) in diameter and about 15 ft (4.572 m) long. They would be arranged on a triangular pitch of about 2 in. (50.8 mm) and fabricated in hexagonal bundles with about 100 tubes per bundle. Each bundle would have its own vapor drum and downcomer tube for liquid return to the bottom of the tubes so that each bundle can be built and replaced individually.

*Fluidized Bed Furnace*

The boiler tube bundles would be assembled in a 12- to 14-ft (3.6576- to 4.2672-m) diameter furnace as indicated in figure 9. The space between the boiler tubes would be filled with a fluidized bed of crushed limestone or dolomite to a depth of about 10 ft (3.048 m). The bed would rest on the lower plate that contains a large number of tuyeres or air nozzles to distribute the fluidizing air evenly across the bed. Crushed coal and fresh limestone feed material would be supplied through pneumatic transport lines that enter the bed through the air distributor plate. The coal would burn in the fluidized bed and about 90 percent of the $SO_2$ released from the coal would combine with calcium in the limestone to form calcium sulfate. The limestone feed rate would be about 25 percent of the coal feed rate. Flyash and the smaller particles of $CaSO_4$ would be carried out of the bed by the flue gas. A freeboard space about 10 ft (3.048 m) high is provided in figure 9 so that the larger particles blown out of the bed will fall back into the bed. The smaller particles carried out of the furnace would be removed from the flue gas by a cyclone separator and a high-temperature (1340° F or 727° C) electrostatic precipitator. As coal and fresh limestone are fed to the furnace, the inventory of ash and spent limestone will tend to increase. Particles too large to be blown out of the bed will be removed by a standpipe or overflow line in the bed that will serve to maintain the bed level. The larger particles will overflow into the standpipe and fall into the ash hopper. Since the bed will contain less than 1 percent coal at any time, there will be a negligible loss of carbon through the overflow line.

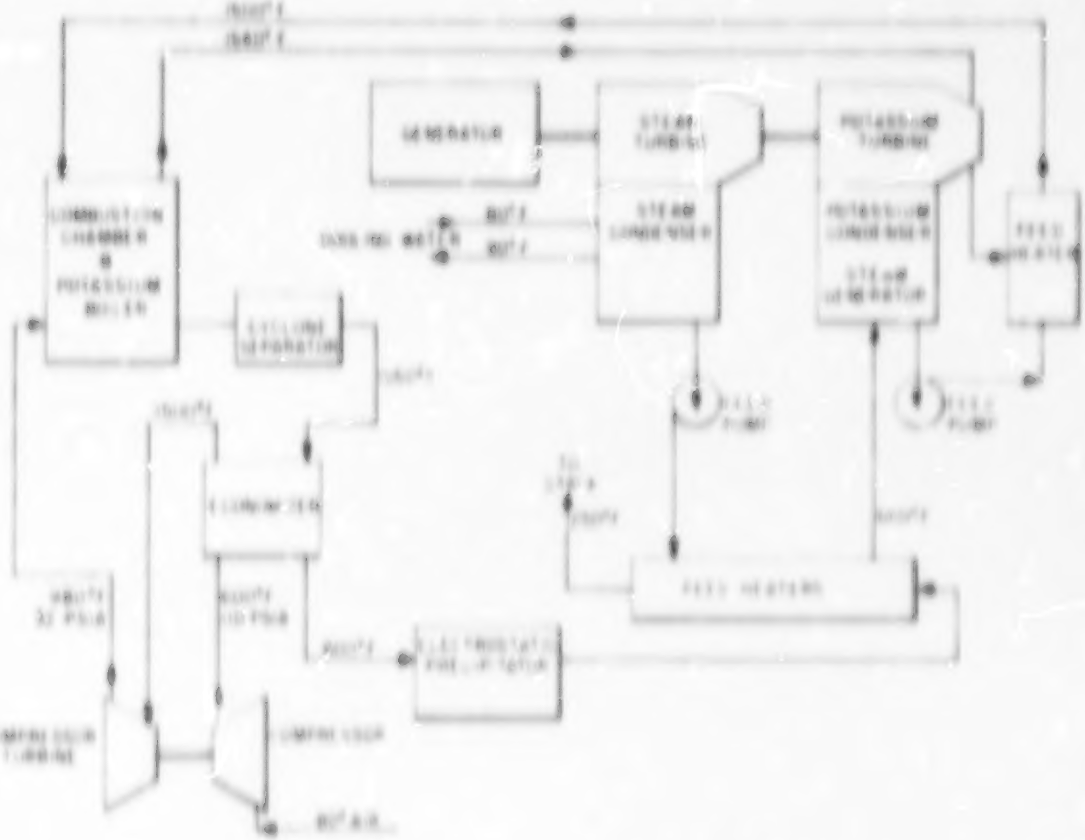
GENERATOR
STEAM TURBINE
POTASSIUM TURBINE
COMBUSTION CHAMBER & POTASSIUM BOILER
STEAM CONDENSER
COOLING WATER
POTASSIUM CONDENSER
STEAM GENERATOR
FEED HEATER
CYCLONE SEPARATOR
FEED PUMP
FEED PUMP
ECONOMIZER
TO STACK
FEED HEATERS
32 PSIA
ELECTROSTATIC PRECIPITATOR
COMPRESSOR TURBINE
COMPRESSOR
80° AIR

Figure 7. Flow sheet for the proposed coal fired potassium vapor topping cycle.

*Economizer*

The economizer will transfer heat from the flue gas to raise the temperature of the combustion air to 1,500° F (816° C) so that it may be used to power the turbine that drives the compressor and thus contribute to the cycle thermal efficiency. The heat load of the economizer will be about 20 percent of the heat input to the furnace. The flue gas temperature will be reduced to about 800° F (427° C), a temperature level that should present no special problems in the design of the electrostatic precipitator.

The other components in the coal fired system, such as the potassium turbine and the potassium condenser-steam generator, will be the same as those for the gas fired system.

## ENVIRONMENTAL EFFECTS

The potassium vapor topping cycle has the advantage that it will reduce fuel requirements by about 25 percent, thus reducing the demand on our fuel resources and the adverse effects of mining and drilling operations. Further, if a fluidized-bed coal combustion system can be employed, high-sulfur coal can be used. The higher efficiency also reduces both the total gas flow to the stack and heat rejection to the environment. The waste heat rejected from the steam condenser will be reduced by about 33 percent. On the other hand, the inventory of alkali metal poses a potential fire hazard and environmental problems. These and related problems are discussed in this section.

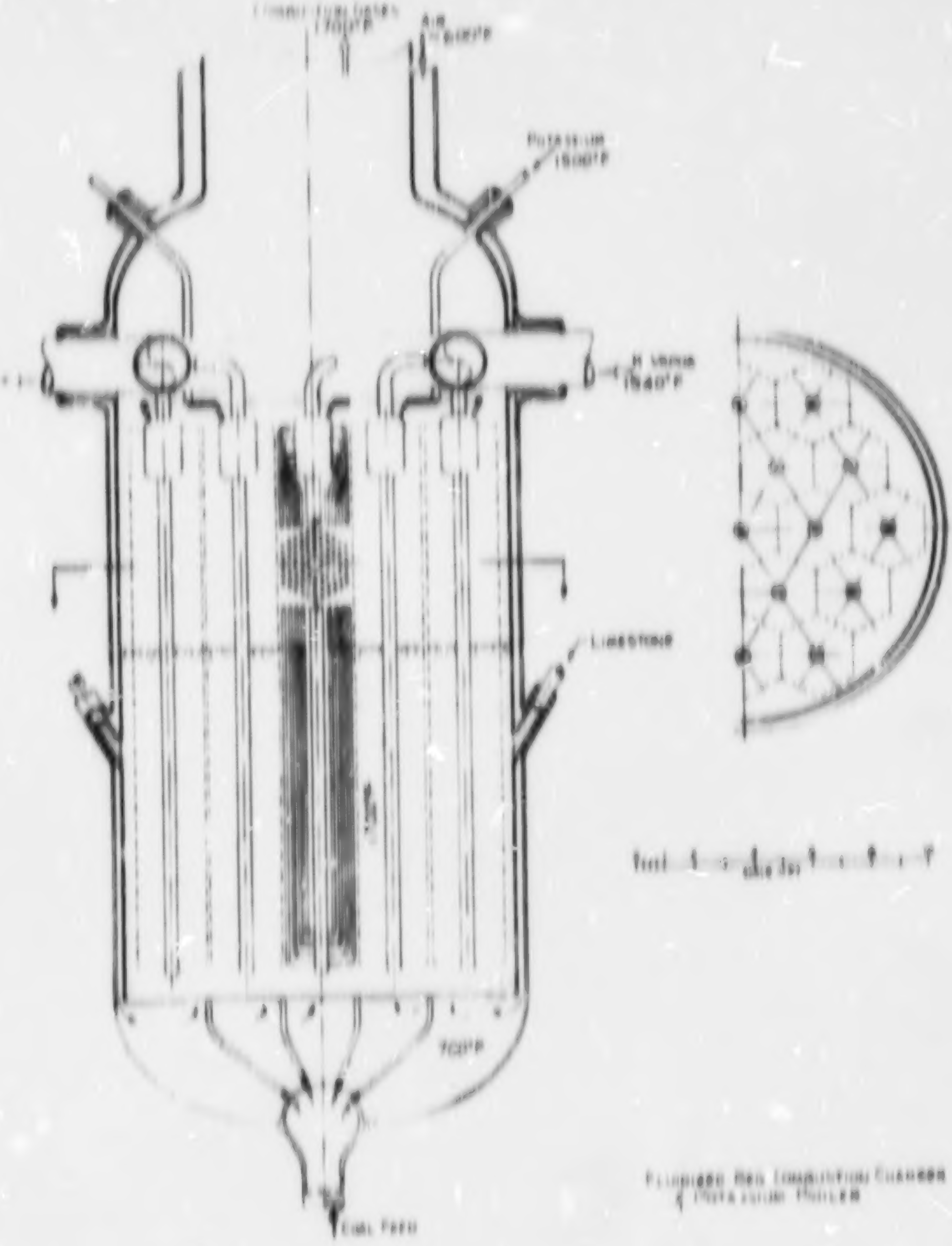
Air
Potassium
Limestone
Coal Feed
Fluidized Bed Combustion Chamber
& Potassium Boiler

Figure 8. Conceptual design for a fluidized bed combustion chamber and potassium boiler.

### *Potassium Leak to the Atmosphere*

The potassium inventory of the plant might conceivably escape into the gas turbine exhaust stream passing up the stack, and in this manner might contaminate the atmosphere in the area with potassium hydroxide. The possibility of such an event is much reduced by the fact that the potassium boiler would normally operate at only 15 psi (1.0545 kg/cm²) above atmospheric pressure (well below the furnace gas pressure) and the potassium condenser would operate with a potassium vapor pressure of only about 1.5 psia (.10545 kg/cm²). Further, cutting off the fuel flow to the burners would cause the potassium boiler temperature to drop rapidly, and when it drops to 1,400° F (760° C) it would be down to atmospheric pressure.

### *Emissions of Sodium and Potassium in Stack Gases*

Some perspective on the magnitude of this hazard can be obtained from a comparison with conventional coal-fired steam plants. The amount of sodium and potassium in the coal burned in such plants commonly runs about 2 percent of the ash content, and the ash content commonly represents about 10 percent of the weight of the coal burned. Better than average precipitators in the stack remove about 99 percent of the ash from the stack gases. Thus, even if precipitators are employed, in conventional coal-fired plant, the weights of sodium and potassium commonly present in the gases leaving the stack amounts to about 0.004 percent of the weight of coal burned. The average coal plant burns almost 1 lb/kWe hr (.45359 kg/3.6J), or about 12,000,000 lb/day (5,443,080 kg/day) for a 500 MWe (500 MJ/sec) plant. This gives a discharge of about 500 lb/day (227 kg/day) of sodium and potassium up the stack, or about 4 percent of the total potassium inventory of 10,000 lb estimated for 1 of the 4 furnaces envisioned for a proposed 600 MWe (600 MJ/sec) potassium-steam binary vapor cycle plant. Note that if no attention is given to minimizing the potassium inventory, the boiler design may give ~20 times that of ORNL design (refs. 7,8). Over 20 years of experience with liquid metal systems at ORNL indicates that one would never expect to have as much as 4 percent of the liquid metal inventory get into the stack gases even in a bad accident, particularly in a system in which the pressure in the furnace would be above that in the liquid metal system. Thus, the release of alkali metal compounds to the atmosphere in a bad accident would probably be no more than that emitted daily from conventional coal-fired plants with precipitators. However, the potassium would probably be emitted as the hydroxide rather than a sulphate, so that it would present a much more serious problem if a potassium leak occurred. To avoid trouble, a wet scrubber could be installed at the base of the stack and activated if needed.

### *Stack Emissions Under Normal Conditions*

The emission of pollutants up the stack under normal operating conditions would be very low for all of the fuels being considered: gas, oil, or coal.

The gas burner built for the potassium boiler tube bundle makes use of recirculation of part of the combustion gas to lower the temperature in the gas flame and thus reduce the amount of $NO_x$ produced. Tests on a one-tenth scale model of the burner with flue gas recirculation of 12 percent gave an $NO_x$ emission of 35 ppm at atmospheric pressure (ref. 13). This is equivalent to 100 ppm at the full power operating pressure of 8 atm, well below the EPA limit of 186 ppm.

The gas burner will operate with an incoming combustion air flow of 10 percent excess over the theoretical air. The CO emission level found from the tests was 20 ppm for 10 percent excess air supplied and with flue gas recirculation of 12 percent.

### *Oil-Fired Furnace*

The burner for the potassium boiler has not been tested with oil but the results of one investigation indicates that the $NO_x$ emission level of oil-fired furnaces can be reduced about a factor of five with flue gas recirculation (ref. 14). A typical value for $NO_x$ emission from conventional burners with no flue gas recirculation is about 250 ppm. It might be expected that this level could be reduced to 50 ppm for advanced burners at atmospheric pressure. For the potassium boiler furnace operating at 8 atm pressure the corresponding $NO_x$ emission would be about 150 ppm, slightly less than the EPA limit of 186 ppm.

The CO emission level for the oil-fired burner is expected to be similar to that found from the tests of the burner with gas firing, i.e., 20 ppm at 10 percent excess air.

The $SO_2$ emission from an oil-fired potassium boiler furnace will have to be controlled by the use of low-sulfur oil. The use of high-sulfur oil would also probably lead to unacceptably high corrosion rates on the flue gas side of the boiler tubes. Limited tests indicate that high-sulfur oil could be burned in a fluidized-bed furnace.

### *Coal-Fired, Fluidized-Bed Furnace*

The release of $NO_x$ from a coal-fired fluidized bed will be reduced below that of a conventional furnace because of the lower combustion temperature in the fluidized bed. This avoids the formation of $NO_x$ from the nitrogen in the combustion air. Nitrogenous compounds are present in the coal, however, and $NO_x$ will be formed from this source. The amount of $NO_x$ formed will depend on the nitrogen content of the coal and the furnace operating pressure. The $NO_x$ emission level in coal-fired fluidized beds has been found to decrease as the pressure is increased, which is opposite to the trend in gas-fired furnaces where the $NO_x$ is formed from the gases in the air. Experimental results of the British National Coal Board give values of about 400 ppm of $NO_x$ at 1 atm to about 200 ppm at 3.5 atm (ref. 15). Argonne National Laboratory workers found the same results with the $NO_x$ level varying from about 450 ppm at 1 atm to about 200 ppm at 8 atm (ref. 16). Their results indicate that a furnace operating at 2 atm pressure, as would be the case for the potassium boiler furnace, would have an $NO_x$ emission level of about 300 ppm, or 0.4 lb/$10^6$ Btu (0.172 kg/$10^9$ J), as compared to the EPA standard of 0.7 lb/$10^6$ Btu (0.3 kg/$10^9$ J).

The emission level of CO from coal-fired fluidized beds has been found to decrease as the furnace pressure is increased. The results found by Argonne National Laboratory were that the CO level decreased from about 2,000 ppm at 1 atm to 200 ppm at 8 atm (ref. 16). They found a level of about 1,000 ppm at 2 atm pressure.

The principal advantage of the fluidized-bed furnace is that high-sulfur coal can be used as a fuel and the $SO_2$ can be removed from the flue gas by reacting with calcium in limestone or dolomite in the combustion zone of the furnace. The $SO_2$ emission level will depend primarily on the Ca/S mole ratio of the feed material. At a furnace pressure of 2 atm and a temperature of 1,650° F (899° C) a Ca/S mole ratio of about 2.5 should give a reduction of $SO_2$ emission of about 90 percent (ref. 15). For 3 percent S coal, for example, this would give an $SO_2$ level of about 200 ppm. This corresponds to a release rate of about 0.4 lb $SO_2/10^6$ Btu (.172 kg $SO_2/10^9$ J), much lower than the EPA standard of 1.2 lb $SO_2/10^6$ Btu (0.5 kg/$10^9$ J).

The particulate level in the flue gas leaving the bed was found by Argonne to be about 40 lb/$10^6$ Btu (17.2 kg/$10^9$ J) for a velocity of 5 ft/sec (1.57 m/sec) (ref. 16). A cyclone separator with an efficiency of 90 percent would reduce this to 4 lb/$10^6$ Btu (1.72 kg × $10^9$ J). An electrostatic precipitator would remove about 98 percent of the particulate matter in the flue gas leaving the cyclone separator. The particulate emission level in the exhaust stack would thus be of the order of 0.08 lb/$10^6$ Btu (0.035 kg/$10^9$ J) or slightly less than the EPA standard of 0.1 lb/$10^6$ Btu (0.044 kg/$10^9$ J).

## SAFETY PROBLEMS

The most serious set of questions with respect to the safety of the potassium vapor cycle is associated with the possibility of leaks into or out of the potassium system, particularly those that would lead to a potassium-water reaction. This section presents first a discussion of the nature of the failures to be expected, then a review of experience with liquid alkali metal leaks and attendant reactions, and then an appraisal of the probable course of events if failures occur.

### *Stresses, Strains, Cracks, and Ruptures*

A review of experience with tube failures in both conventional boilers and high-temperature liquid metal and molten salt heat exchangers indicates that any one of several different mechanisms may induce difficulty. A common source of difficulty is corrosion on the combustion gas side when the fuel has contained sulfur and vanadium and temperature conditions have favored condensation of volatile corrosive materials on tube walls. The potassium boiler will employ fuels that either contain little sulfur or capture the sulfur with calcium to minimize this sort of difficulty. Local overheating of steam boiler tubes as a consequence of irregularities in gas temperature and velocity distribution has been a cause of many tube failures in superheaters, but this type of problem should not be present in either the potassium boiler or the potassium condenser-steam generator of the reference design.

The recirculating potassium boiler should operate with all of the surfaces exposed to hot gases thoroughly wet with liquid potassium so that the heat transfer coefficient on the boiling potassium side of the tube will be many times higher than that on the combustion gas side, and hence the tube wall temperature will be held close to the boiling potassium temperature.

In the potassium condenser-steam generator, the tube wall metal temperature will be very close to the potassium condensing temperature and hence will be very uniform. By far, the most important source of tube failures in liquid metal or molten salt heat exchangers and an important source of failures in conventional steam generators has been thermal strain cycling (ref. 17). This may be coupled with pressure stress effects in high-pressure steam generators, particularly in the water walls of pressurized furnaces (ref. 18). The bulk of the failures to be expected in the heat exchangers for a potassium vapor topping cycle will probably stem from combined thermal and pressure stresses.

### *Thermal Strain Cycling*

Differential thermal expansion in a complex structure commonly leads to high local stresses that are above the elastic limit, or at least above the creep limit, and hence local plastic flow takes place. A few cycles of this sort ordinarily do not lead to difficulty, but many cycles may induce what is called a low-cycle fatigue failure (refs. 19,20). In high-pressure, low-temperature systems a fatigue crack is likely to lead to a burst type of rupture, but in low-pressure, high-temperature systems where the ratio of the ultimate tensile strength to the design stress is much higher, low-cycle fatigue cracks of this sort progress very slowly and simply result in a gradually increasing leakage rate; they do not lead to a burst type of failure. This is an extremely important point in appraising the types of failure to be expected in the heat exchangers for a potassium vapor topping cycle and the course of events associated with such a failure. It should be noted that experience with high-temperature, high-pressure, fossil fuel-fired steam generators is consistent with this appraisal; failures ordinarily develop slowly and often do not become apparent until the amount of makeup water required to offset the leak becomes substantial. In fact, steam generators are commonly operated for hours or days after a leak becomes large enough to result in losses of thousands of pounds of water per hour. Even with such large leaks, burst type failures are uncommon. Thus, the type of failure to be expected is a slowly developing, low-cycle fatigue crack that will yield a small leak, and if this leak can be detected readily in a liquid metal system, its effects will be negligible and limited to the leak itself. ORNL experience with liquid metal and molten salt heat exchangers is consistent with this appraisal.

## REACTIONS BETWEEN ALKALI METALS AND AIR OR WATER

It has been stated that the greatest handicap faced by alkali metal systems is the impression made upon most of us as junior high school science students when our teachers introduced us to sodium by throwing a small chunk of the metal into a beaker of water. The vivid picture left by these demonstrations has made spontaneous fires and violent explosions seem almost synonymous with alkali metals. In point of fact, if there is not water around, a liquid alkali metal fire is much like a charcoal fire.

An excellent summary of a wide variety of experiments made by many different investigators is presented in reference 21 for work carried out up to 1966. Some 90 references are cited. Much work has been conducted since that date. The following presentation attempts to give perspective to the problems and cites representative cases from this large body of work.

### *Reactions with Air*

Unlike hydrocarbons, the liquid metals have a very low vapor pressure, and as a consequence oxidation can take place only at the liquid surface; the liquid metal does not vaporize to yield a combustible or explosive mixture of air and vapor. As a matter of fact, an oxide blanket tends to form on the liquid surface, and this interferes with the oxidation rate such that if the liquid metal is in a stagnant puddle in an air atmosphere, the reaction rate will be inhibited by the oxide. The oxide density is greater than that of the liquid, hence it tends to sink in the liquid, reducing its inhibiting effects on the reaction.

### *Reactions with Water*

If no air is present, the reaction between water and sodium, potassium, or NaK is rapid and violent, and both hydrogen and steam are evolved. If the hydrogen mixes with air, an explosive mixture is formed and, once a flame front starts in a hydrogen-air mixture, it is likely to develop into a detonation wave so that a violent explosion can ensue (ref. 22). This is the usual course of the reaction in a high school science demonstration; the sodium-water reaction commonly proceeds very vigorously for some time before ignition occurs and then, when a substantial quantity of a hydrogen-air mixture has accumulated, this ignites, detonates, and it is the hydrogen that is responsible for the explosion.

### *Reactions with Steam*

Because of its much lower density, steam reacts with alkali metals at a much lower rate than water. Steam is commonly used to clean out the residual liquid metal from components of alkali metal systems when they are removed for inspection.

### Experiments with Small Scale Units

A series of small-scale experiments run at Mine Safety Appliances Company, (refs. 23,24) has yielded some valuable insights into the possible effects of leaks in an alkali metal-heater generator. These tests entailed injection of water into alkali metal or vice versa with pressure differentials of the order of 200 psi at metal temperatures around 600° F (316° C) using orifices from 1/8 to 1/2 in. (3.175 to 12.7 mm). The results indicated that, for the system tested, if a leak occurs in a sodium- or NaK-to-water heat exchanger fitted with a blowoff valve or a rupture diaphragm and a stack, the peak pressures developed were only a little higher than those for which the valve or diaphragm was designed. It was found that if the liquid metal temperatures were above 600° F (316° C), there were no violent pressure surges and there was smooth relief of the gas evolved via the pressure relief valve (ref. 22). Further, if the relief valve can be located in the water system, the peak local temperature in the reaction zone can be kept relatively low because the heat released will go into vaporizing the water (ref. 23). If the relief valve is placed in the water system, the liquid metal system must be designed to take the same peak pressure as the water system—a step that will not be attractive.

It must be emphasized that the sequence of events and the magnitude and frequency of pressure and temperature fluctuations may vary widely from one system to another as a consequence of differences in system size and proportions, including surge volumes, size and length of connecting piping, location of relief valves, etc.

*Differences Between Sodium, Potassium, and NaK*

The tests at the Mine Safety Appliances Company were carried out with sodium, NaK, and potassium. The shape of the pressure-time curves for typical simulated leaks between liquid metal and water systems differed somewhat between the tests with sodium and those with NaK, but there were no important differences between the curves for NaK and those for potassium (ref. 23). Typical sets of curves of this sort are shown in figures 9 and 10.

### Experiments with Large Scale Units

A particularly fine series of experiments has been run in the United Kingdom using both 1/8-scale and full-scale tube banks to investigate the effects of leaks in sodium-heated steam generators (refs. 25,26). The tests were run with leaks designed to simulate the full range

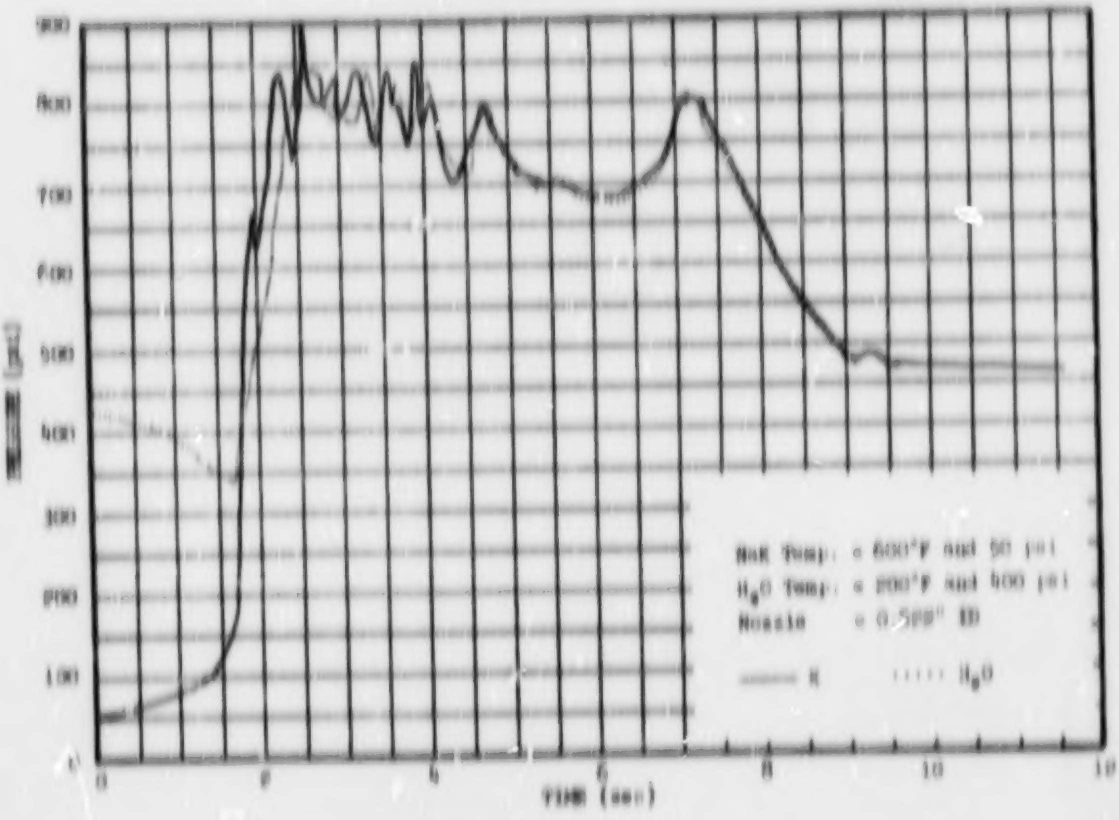

Figure 9. A typical curve showing the system pressures as a function of time after initiation of injection of water into NaK in tests at Mine Safety Appliance Company (reprinted from ref. 22).

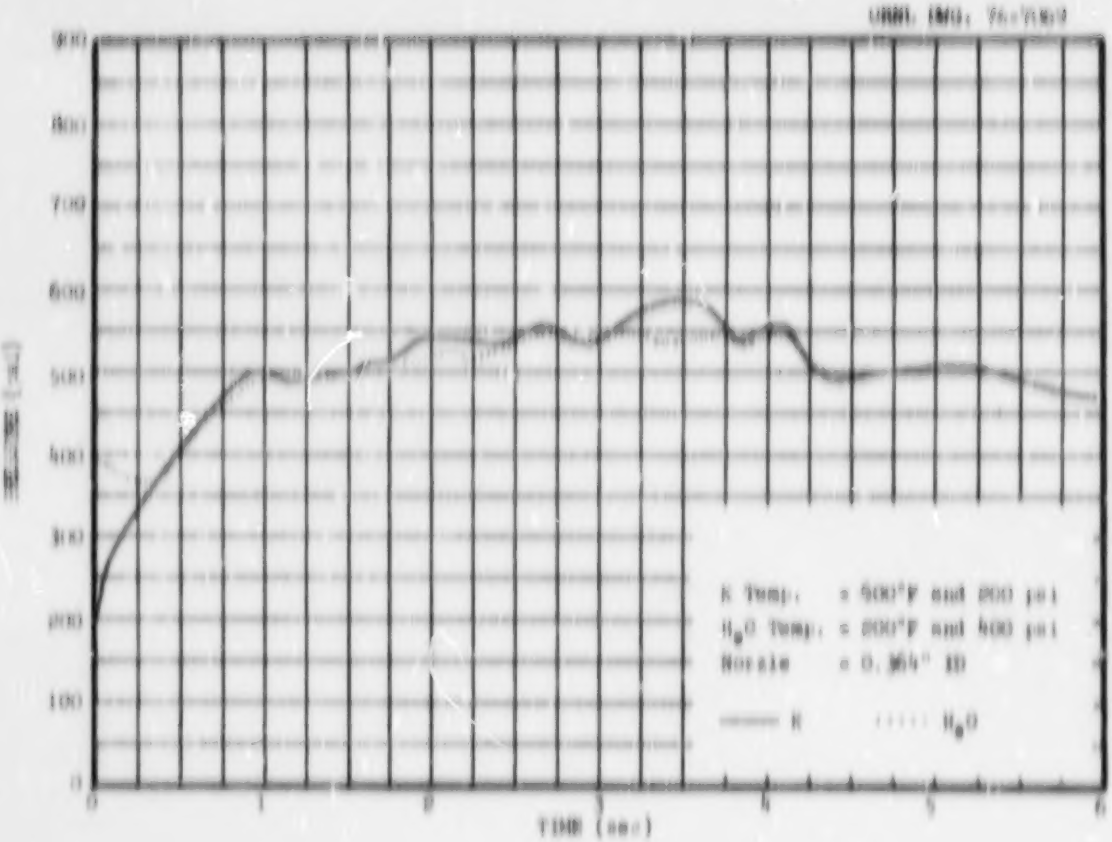

Figure 10. A typical curve showing the system pressures as a function of time after initiation of injection of water into potassium in tests at Mine Safety Appliance Company (reprinted from ref. 22).

of effective orifice sizes that might be experienced in service, i.e., from pinhole leaks of 1 ml/min to a wide open tube. The leak duration in the test ranged from as much as an hour for the pinhole leaks to only a few seconds for the large-scale leaks. The systems were instrumented to give a detailed insight into the transient local temperatures and pressures. The instrumentation included strain gages on the heat exchanger shell. The test work was carried out in close conjunction with analytical work directed at predicting the effects of changes in operating conditions.

Results of the tests were generally consistent with the tests described above carried out by the Mine Safety Appliance Company, but much more detailed insights into the conditions to be expected in a full-scale heat exchanger were obtained. Detailed examinations of the heat exchangers after the tests were made to determine the character of the reaction products. This work indicated that about half of the hydrogen from the water that reacts with the sodium is blown off as gaseous hydrogen, and the balance remains combined either as NaOH or NaH. The hydrogen bubbles may go into solution in the sodium depending on the amount of hydrogen released. The NaOH and NaH tend to settle out and, because of their higher melting point tend to freeze in the lower temperature regions.

*Test Conditions*

The tests were carried out with water pressures up to 2,300 psi (161.68 kg/cm$^2$) with initial sodium temperatures generally in the vicinity of 900° F (500° C). The tests were run with plain carbon steel tubes, ferritic chrome-moly tubing, and austenitic stainless steels. Particular attention was given to corrosion effects when the heat exchanger tubes were examined subsequent to each leak test. The carbon steel tubing showed substantial corrosion, the chrome-moly tubing showed a mild amount of corrosion, and there was very little corrosion of the stainless steels. Tests run by other experimenters have sometimes turned out less favorably. One major factor is the length of time that elapses before the corrosive products of the reaction are cleaned out of the equipment.

*Damage to Tubes Adjacent to a Leak*

A major concern in attempting to envision the course of events in the event of a leak in the steam generator is damage to adjacent tubes and the possibility of a rapid spread of the failure. This may occur as a consequence of corrosion, erosion, or local overheating. The temperatures that develop in the reaction zone may reach around 2,400° F (1,300° C), and this may so weaken adjacent tubes as to lead to failures. Whether or not such failures occur appears to be very much a function of the character of the jet that emerges from the leak. For example, tests involving 2,300 psi (161.69 kg/cm²) water jets in full-scale tube bundles led to failures when the jets impinged at close range on adjacent tubes (ref. 26). These failures occurred in a matter of a few seconds, and hence provided a mechanism for progressive failures of the sort that occurred in the NaK-heated steam generator of the Fermi reactor plant (ref. 27). This phenomenon, commonly referred to as "tube wastage," places a strong premium on detecting the development of such a leak very quickly so that the pressure on the water side can be relieved and the water and sodium system pressures brought into pressure equilibrium (ref. 28). When this has been done, the reaction rate drops sharply and the leak may even plug with sodium oxide when the pressures in the two systems equalize (ref. 23).

If steam free of liquid leaks into the liquid metal side of a steam generator, the reaction between the steam and the liquid metal takes place at a greatly reduced rate. This happens partly because the density of the steam is much lower than that of water, greatly reducing the rate at which the two can react at the interface, and in part because the hydrogen formed inhibits the movement of steam to the liquid metal surface by convective circulation (ref. 29). The reaction proceeds quietly without the violent pressure fluctuations and noise commonly associated with liquid water-sodium reactions. This in turn suggests that steam generators for liquid metal systems should employ a reentry tube steam generator design (ref. 11) of the sort shown in figure 6 so that any leak that might develop would consist only of steam with essentially no liquid water. When this is the case, there should be no problem with tube wastage because the latter is a phenomenon that apparently involves both erosion and corrosion, and requires the presence of liquid water in the jet emitted from the leak. This thesis is borne out by experience with steam leaks in the superheaters of conventional power plants; if the region around the leak is reasonably free of ash deposits, the steam jet from the leak will not "cut" the adjacent tube.

## Implications of Leak Test Experience

A number of important points emerge from a review of the experience gained from investigations of leaks in an alkali metal-heated steam generators. These observations may be summarized as follows:

1. Both analyses and test experience indicate that a high-pressure jet of steam leaking into a tube matrix filled with alkali metal commonly will not induce failures in adjacent tubes, whereas high-pressure jets of water usually induce leaks in adjacent tubes.
2. If a condensing alkali metal vapor is employed to heat a steam generator rather than a liquid alkali metal, the probability of a high-pressure steam jet inducing a failure in an adjacent tube should be very low, the pressure fluctuation associated with the leak should be minor, and the temperature excursions in the reaction zone should be much less than if the jet were going into liquid metal.
3. There is a strong incentive to detect the leak before large quantities of reaction products can be formed because these may plug the lines and make drainage and cleanup of the system difficult.
4. Detection of a leak into an alkali metal condenser can be made much more rapidly than detection of a leak into a liquid alkali metal system if the condenser is made to concentrate the noncondensibles in a pocket at one end. This stems from the much higher velocity of the liquid metal vapor and the much more effective collection of noncondensibles in a condenser than of gas bubbles in a liquid system.
5. It is highly desirable to limit the inventory of both liquid metal and liquid water in an alkali metal-heated steam generator so that the quantities of material that can react can be limited by closing valves or other operator action.

As will be discussed further in the following sections, the reference design for the potassium condenser-steam generator considered here takes advantage of all of the above observations to obtain a design that should be singularly unlikely to develop a leak, and if one develops, it should be much less sensitive to the leak than a liquid metal-heated steam generator.

## ANTICIPATED FAILURE MODES IN THE POTASSIUM TOPPING CYCLE

Operational and safety problems were major factors in the design philosophy on which the system of figures 1 through 5 was based. Every effort was made to minimize the possibility of a failure, and, if one should occur, to minimize its consequences. An effort was made to take advantage of the fact that, in the system proposed, the pressure in the potassium system will be below that of either the combustion gases in the furnace-potassium boiler units or the steam in the potassium condenser-steam generator units. As a consequence, if a leak develops, leakage will be into the potassium system rather than from the potassium system out into the combustion chamber or the steam generator.

*Combustion Gas Leak into the Potassium Boiler*

A leak of combustion gases into the potassium boiler will lead to the formation of potassium oxide in the recirculating liquid potassium. Little or none of this potassium oxide will be carried out of the boiler into the balance of the system. The low pressure in the potassium boiler implies low-pressure stresses and hence, if a leak does develop, it will probably stem from thermal strain cycling and can be expected to progress slowly. This in turn means that the damage can be limited if the leak can be detected in the early stages. This is particularly important because corrosion in the liquid potassium system will proceed fairly rapidly if the oxygen content of the potassium builds up to more than 500 to 1,000 ppm. On the other hand, if the leak can be detected in its early stages, the corrosion will not have an opportunity to become appreciable, the quantity of reaction products will be small enough to remain in solution so that "crudding up" of the system will not be a problem, and the repair operations can be limited to sealing the leak itself and removing the oxygen from the potassium. (Sealing of the leak in a heat exchanger tube is likely to require removal and replacement of a complete tube bundle module.)

*Steam Leak into the Potassium Condenser*

If a leak develops in the steam generator, the steam jetting into the potassium condenser will react with the potassium vapor to form potassium oxide and hydrogen. Inasmuch as the potassium condenser will have a large vapor volume space available, there will be plenty of space for the hydrogen and no explosion or even large increase in pressure will occur. (This situation is completely different from that in a liquid-metal-heated boiler in which there is no free volume on the liquid metal side and into which the hydrogen from the reaction can expand.) As the hydrogen builds up in the condenser, it will block the flow of potassium vapor into the condenser and produce a back pressure on the potassium turbine. Only a few pounds of steam leaking into the condenser would produce a marked change in the turbine back pressure, which would be obvious to an operator and could be used to trip a warning signal.

Although extremely unlikely, if a large steam leak were to develop as a consequence of a burst type of failure, the inherent nature of the double-walled tube configuration and inlet orificing of the inner tube of the reentry tube boiler is such that vapor rather than water would be injected into the potassium region (fig. 9), and the rate of injection would be relatively low—about 4 lb/sec (1.816 kg/sec) per ruptured tube. This would lead to an increase in the pressure in the condenser at a rate of about 1 psi/sec (.0703 $\text{kg/cm}^2$ sec), or about 60 psi/min (4.218 $\text{kg/cm}^2$ min). Thus, if the potassium condenser were designed to take an internal pressure of 60 psi (5.218 $\text{kg/cm}^2$), and if the flow of either steam or potassium into the condenser could be stopped within 1 min of the first evidence of the rupture, the damage would be limited to the broken tube. For the extreme case, assuming the abrupt, complete rupture of a steam generator tube, the potassium condenser pressure would rise to about 4 psia, or about three times its normal values, in about 3 sec. This would be easily and reliably detectable and could be the basis for closing valves in the feed water supply line. If this were done in an additional 10 sec, the inventory of superheated water in the boiler design proposed would be exhausted in another 15 sec in the course of the "coast-down," and the peak pressure in the potassium condenser would be held to about 15 psig (1.0545 $\text{kg/cm}^2$). To protect against the contingency that no action might be taken, a rupture disc should be provided to blow off at perhaps 40 psia (2.812 $\text{kg/cm}^2$).

It should be emphasized that a complete rupture of a tube appears highly unlikely; all experience to date indicates that a leak would develop gradually as a result of thermal strain cycling and, if the leakage were sufficient to be detectable, the system could be shut down in an orderly fashion before any great amount of leakage had occurred. Thus, it is apparent that there is a strong premium to detecting trace amounts of steam or gas leakage into the potassium system.

## LEAK DETECTION

*Steam Leaks Into Potassium*

One good way of detecting just a trace amount of steam leakage into the potassium condenser would be to design the potassium vapor flow passages to sweep any noncondensibles to a small region at one end of the potassium condenser in much the same fashion as is done in conventional steam condensers. In the latter, the noncondensibles, largely air, are swept to a small region at one end of the steam condenser and the air is removed with a steam ejector. Similarly, a potassium condenser could be arranged so that noncondensibles would be swept to a small region in which a hydrogen sensor could be located. This might take the form of a nickel or palladium window separating the potassium vapor region from an evacuated region. An ion gauge in the vacuum region would quickly register the presence of hydrogen that would diffuse through the palladium window if there were hydrogen present in the potassium vapor. A device of this sort is under development for the LMFBR (ref. 30).

*Gas Leaks Into Potassium*

It is difficult to measure quantitatively the amount of oxygen in liquid potassium. However, experience with NaK cold traps indicates that it would be possible to make use of a sensitive plug indicator in the potassium system if a few percent of sodium were added to the potassium. This would reduce the vapor pressure over the potassium by a small amount—less than 1 psi (.0703 kg/cm$^2$) for around 3 percent sodium in potassium—but it would provide a sensitive indication of the presence of oxygen in the potassium. Further, it would provide a means for oxide removal by cold trapping, and this would be advantageous from the standpoint of other aspects of system operation. Alternatively, an electrochemical, on-line $O_2$ concentration meter is being developed for sodium circuits under the LMFBR program, and this may prove suitable for potassium systems.

In practice, a cold plug indicator probably ought to be employed in connection with each tube bundle in the furnace-potassium boiler units. Thus, about 30 pipes about 1/2 in. (12.7 mm) in diameter would have to be carried out from the 30 tube bundles in the design proposed, and would have to penetrate the furnace pressure vessel wall. Note that these penetrations would not be subject to the stringent leak-tightness requirements of the potassium system because they simply contain combustion gases.

## STEAM EXPLOSIONS

The possibility of a steam explosion, although small, is inherently present in any steam boiler. In the type of boiler proposed, the inventory of superheated water in the boiler is only a few percent of that present in conventional coal- or oil-fired steam boilers, and hence should reduce the hazard potential associated with this type of accident to a much lower level than in conventional coal-fired steam boilers.

## FUEL FIRES

There is always a fire hazard associated with the inventory of fuel maintained at a power plant. If the amount of fuel in storage is determined by the number of days' supply considered necessary, a plant of a given power output but with a higher thermal efficiency will require a smaller inventory of fuel. The proposed potassium-steam vapor cycle will have a thermal efficiency about double that of a conventional gas turbine plant, and hence would require about half the fuel inventory. If compared with a conventional oil-fired steam plant, the fuel inventory would be three-fourths of that for the conventional plant.

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# A TOPPING CYCLE FOR COAL-FUELED ELECTRIC POWER PLANTS USING THE CERAMIC HELICAL EXPANDER[*]

B. Myers, R. Landingham, P. Mohr, and R. Taylor[†]

## Abstract

*We advocate ceramic helical expanders as the work output element in a 2,500° F direct coal-fired Brayton topping cycle for central power station application. When combined with a standard steam electric power plant cycle, such a cycle could result in an overall thermal conversion efficiency in excess of 50 percent. We enumerate the performance, coal tolerance, and system-development-time advantages of the ceramic helical expander approach. We provide a perspective on the choice of design and materials.*

*A preliminary consideration of physical properties, economic questions, and service experience has led us to a preference for the silicon nitride and silicon carbide family of materials. A program to confirm the performance and coal tolerance aspects of a ceramic helical expander system is planned.*

## INTRODUCTION

In the United States, about 25 percent of our fuel consumption is in the area of electric power generation. Most projections show that total fuel consumption will double before the end of the century and that the percentage used for the generation of electricity will increase also. A projection for the year 1990 is shown in figure 1.

The present average thermal efficiency of the electrical conversion process is about 34 percent, and for modern fossil-fueled plants it is 40 percent. Technologies for increasing the conversion efficiency in the power plant to the range of 50 to 60 percent are near at hand, as is well known. In the main, these new technologies involve the addition of a topping cycle to new or existing conventional steam plants. A topping cycle increases efficiency by extracting additional energy from a fixed quantity of fuel. A perspective on the prospect for progress of power plant thermal efficiency with time is given in figure 2. An increase to 50 percent could enable us to conserve as much fuel in the year 2000 as we now consume for electric power generation.

The principal contending concepts for the topping cycle are:

- the Brayton-topped steam cycle or gas-turbine combined cycle with cycle temperatures above 2,300° F,
- the Rankine-topped steam cycle or potassium-vapor-turbine combined cycle with cycle temperatures of ~1,500° F,
- the open-MHD-topped steam cycle with cycle temperatures of ~4,800° F.

Each has its advantages and disadvantages. All, however, share in common the challenge of accommodating the available fuel resources, particularly the more abundant coals.

We would like to describe an alternative in the Brayton-cycle family that makes use of a novel ceramic engine, a helical rotor expander, which is presently unexploited. We see evidence that this system can be built from available ceramic materials in a shorter time, with greater fuel tolerance, and at lower cost than competing systems. It would provide topping-cycle service at temperatures approaching the limit for conventional heat sources.

## SOME PERSPECTIVES ON HELICAL EXPANDERS

We have for some time considered alternative conversion machinery that might accomodate the strength properties and relatively low debris tolerance of ceramic structures (ref. 1). The most promising candidate identified is the helical rotary machine originated by Lysholm (ref. 2). This positive displacement machine, operating in the expansion mode, has a combination of characteristics that are favorable for ceramic construction:

- Characteristic centrifugal stresses, as compared with those in a bladed turbine, are down by as much as a factor of 10 because of lower tip speed.
- Rotor temperatures are significantly lower than the inlet temperature because of the cyclic nature of the device.
- The geometry is rugged, providing high large-debris impact resistance.
- Small debris such as fly ash has a low velocity relative to the rotor and can pass freely through the machine without appreciable erosion potential; there is virtually no way to design a ceramic blade and vane immune to rapid erosion or impulsive damage from debris.

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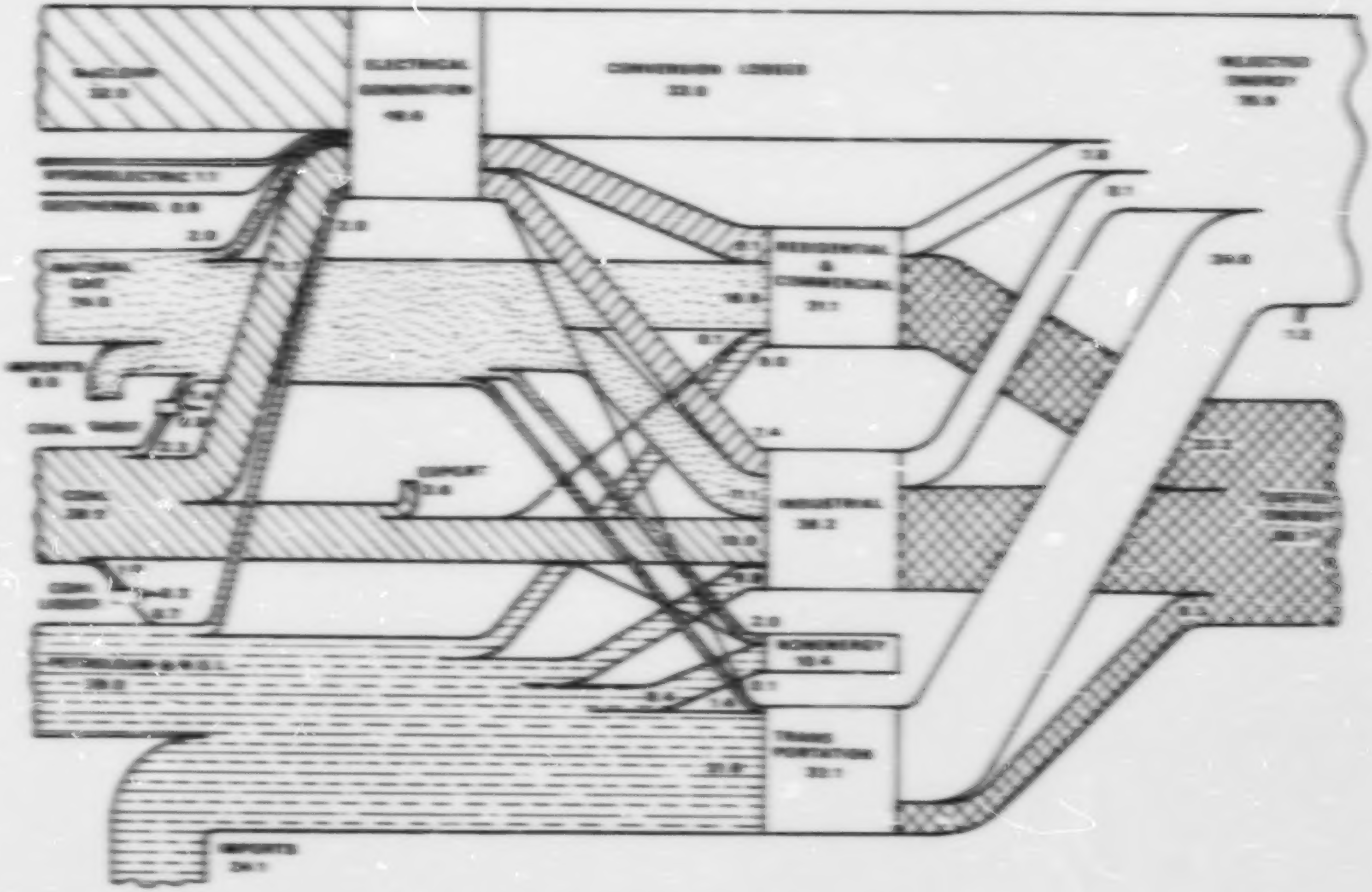
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PETROLEUM & N.G.L.
RESIDENTIAL & COMMERCIAL
INDUSTRIAL
NONENERGY
TRANSPORTATION
USEFUL ENERGY
IMPORTS

Figure 1. The U.S. energy flow in 1990, modeled after the National Petroleum Council intermediate-demand case. All values are in $10^{15}$ Btu ($2.12 \times 10^{15}$ Btu = $10^6$ bbl/day of oil). Total energy consumption is $148.6 \times 10^{15}$ Btu.

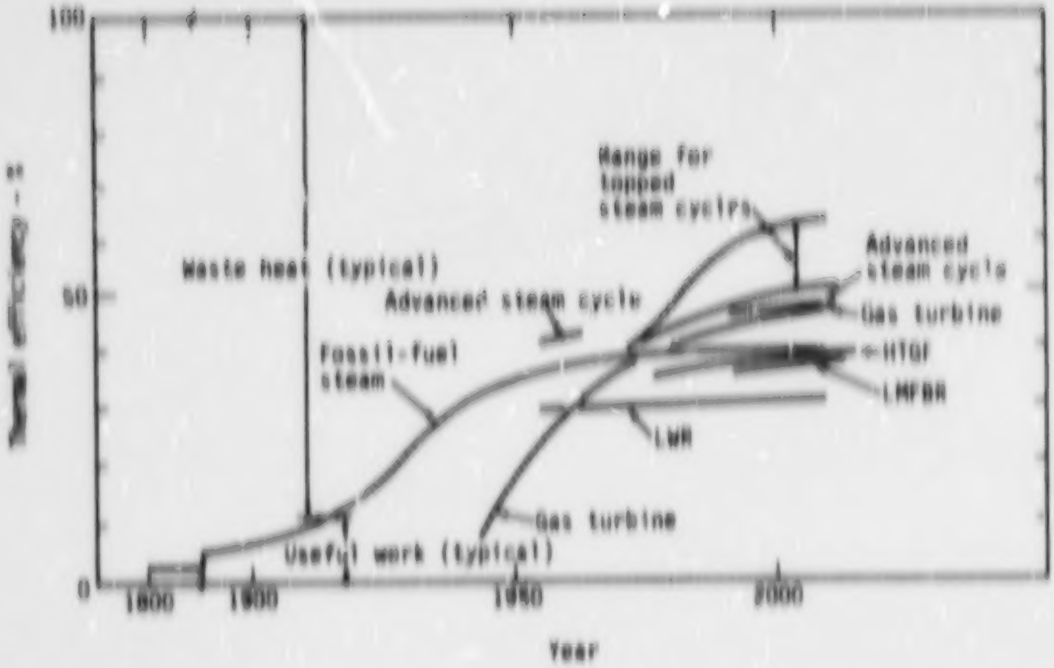


Figure 2. Power plant efficiency trends, actual and projected.

An exploded pictorial view of the helical expander is shown in figure 3. Its operation, like that of a reciprocating engine, involves admission, cutoff, expansion, release, and exhaust phases as illustrated in figure 4.

Axial-flow gas turbines develop power symmetrically in the tangential direction. Blade and spool thrust loads are present, but they can be carried to any arbitrary thrust-bearing location, and they can be balanced by compressor thrust or passive discs. In helical expanders, by contrast, flow is essentially diagonal, as can be deduced from figure 4. The gas enters in the top front pocket, as shown in the view at the left, and it progresses toward the sides and back end, releasing, as shown in the view at the right, when expansion terminates as the shaded pocket reaches the opposite end of the machine.

There are radial loads in the machine due to the integral of the pressures over all rotor surfaces. There is also thrust and torque due to the unbalanced pressure on the net area of leading flanks as opposed to trailing flanks in each chevron. The differential area is considerably smaller than the total so that turning forces are small in comparison to the radial loads. The radial loads are highest on the male rotor and toward the inlet end. A bearing buried in the rotor or stiff rotor extensions would probably be necessary to reduce dynamic effects and to keep the alignment necessary for close clearances between rotors and case. The design of these high-speed bearings and the associated seals will constitute an appreciable part of any development program.

The power per unit of rotor diameter is similar for expanders and turbines of similar power output. The screw expander runs at about a third of turbine tip speed, but the gas enveloping regions occupy a much larger fraction of the cross-sectional area. In addition, the expander has two rotors instead of one.

The principal inefficiencies in the expander are associated with the intake and exhaust processes, the leakage between cutoff and release, and the bearing and seal losses. The leakage is due to rotor and case clearances and inlet end seals. Tighter clearances and seals reduce the leakage, but they also increase mechanical losses and design complexity.

Figure 5 shows test data on adiabatic efficiency ($\eta_{ad}$) versus the pressure ratio for a 31-in. helical compressor used in the first, U.S. Navy experimental gas turbine (ref. 3). A helical expander of this size would deliver about 5 MW under our topping cycle conditions. We note in figure 5 that $\eta_{ad}$ has a fairly broad peak in

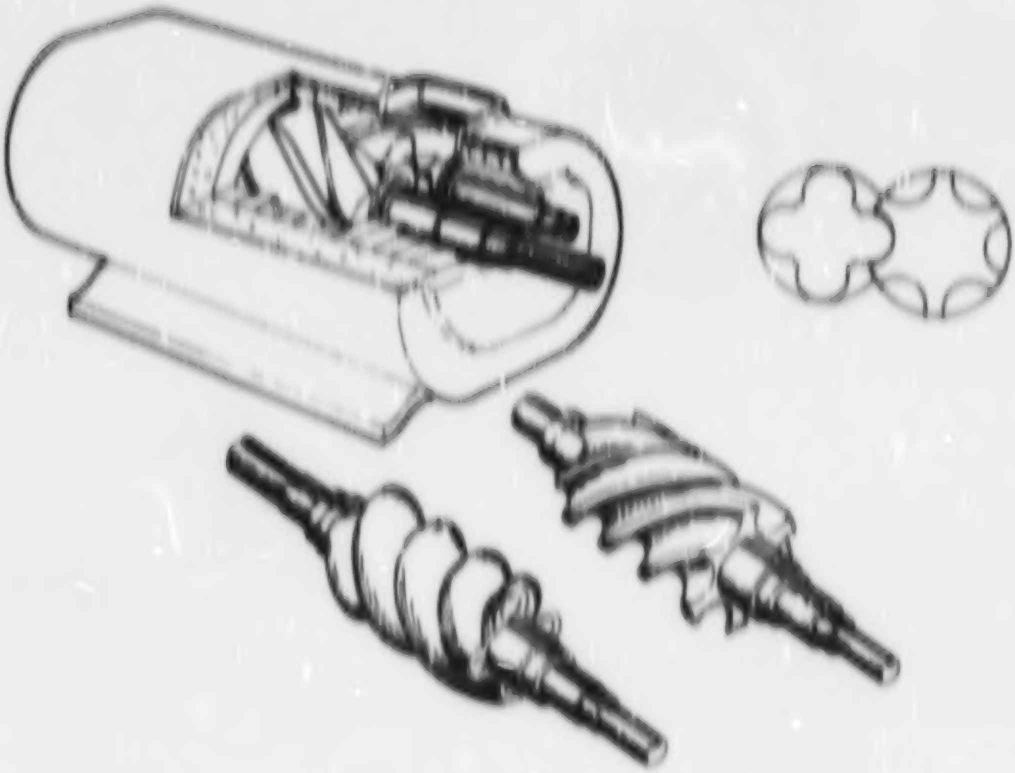
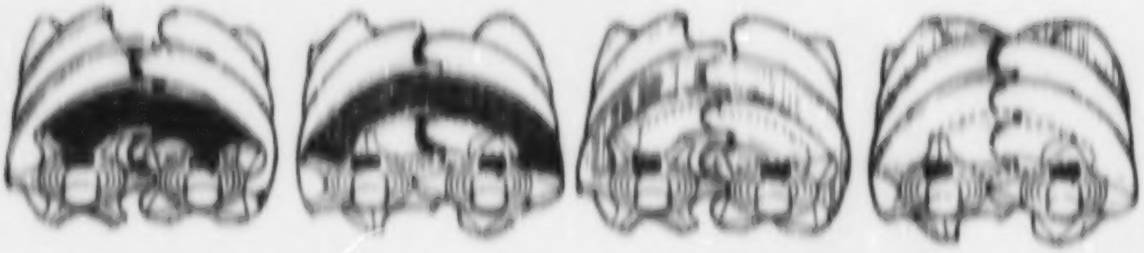


Figure 3. Exploded view of the helical expander.



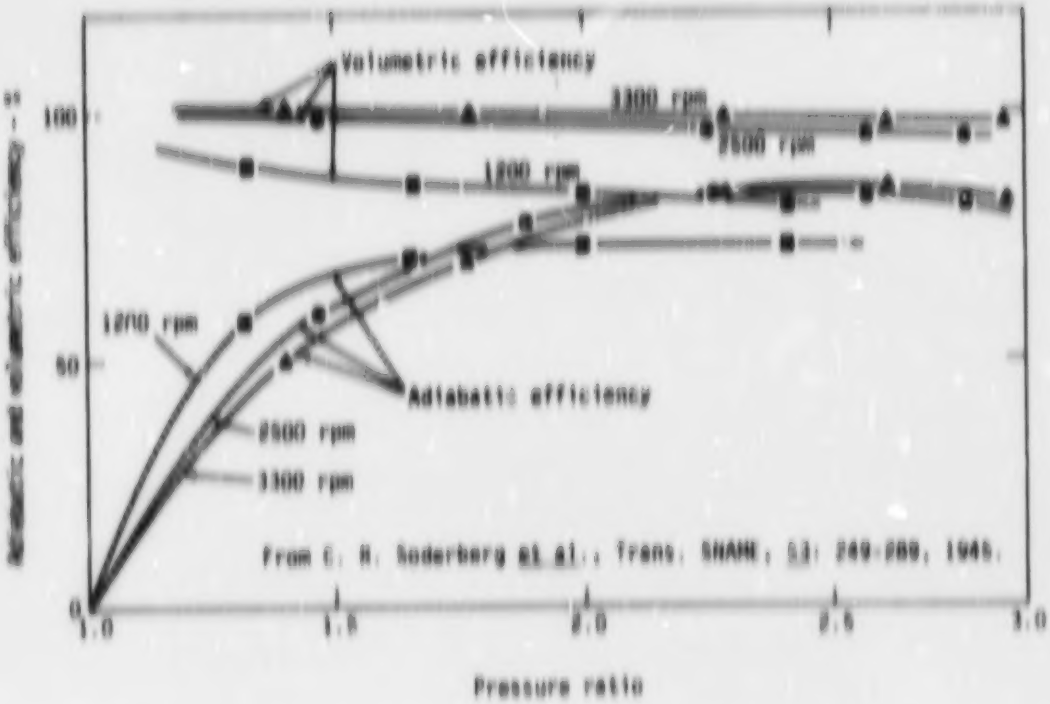
High-pressure gas is forced into the pockets, between the lobes of the rotors and the case

Turning cuts off the intake port and traps gas in the pockets

Further turning increases the volume of the pockets allowing expansion to occur

Discharge occurs when the exhaust ports are uncovered by the lobes

Figure 4. The operation of a helical expander.



From C. R. Soderberg et al., Trans. SNAME, 53: 249-289, 1945.

Figure 5. Test data on the adiabatic efficiency versus pressure ratio for 21-in. helical compressor (from ref. 3).

the region of 85 percent for the higher speeds. At this pressure ratio, as will be seen in figure 6, an expander should have the same efficiency, which means that it would be deficient by six to eight points compared to a corresponding turbine. The falloff of $\eta_{ad}$ for the compressor at 1,200 rpm is probably due to greater leakage for the longer time of expansion.

Figure 6 shows an estimate of the effects on $\eta_{ad}$ of pressure ratio, size, and expansion or compression operating mode for a constant-tip-speed family of machines (ref. 4). The gain with size is due to surface-to-volume effects, the larger sizes of geometrically similar machines having less relative leakage area. Further advantage can come from scaling clearances at less than linear. An optimum pressure ratio r is shown because at low r, the power increases more rapidly with increasing r than does the leakage, and at high r, where some of the leakage is at sonic velocity, it increases more slowly with increasing r. The persistence of the efficiency of the expander mode with increasing r is mostly due to the fact that expanders are generally run at higher temperatures than compressors so that the relative leakage is lower.

A perspective on the steady-state radial temperature profile across the rotors in the expander is shown schematically in figure 7. The temperature range in the left zone is set by the requirements of the topping cycle, and the base temperature in the right-hand zone is set by the lubricating-oil temperature limit for conventional bearings. The intermediate profile depends on the relative thermal conductances of the gas film, the rotor, and the oil film. The ripple shown on the outside portion of the rotors is associated with the cyclic gas temperature, the heat transfer conditions at the surface, and the thermal diffusivity of the rotor material. It is seen that in contrast to that for axial flow machines, the peak steady-state rotor temperature can be considerably lower than the expander inlet temperature. Figure 7 also shows combustion and ash temperatures, material strengths, and thermal stress indices for reference.

The temperature drop across the hollow rotor as shown in figure 7 gives rise to thermal stresses that are compressive on the outer surface and tensile on the inner surface. These stresses are superimposed on the rotational stresses, but they are different in character be-

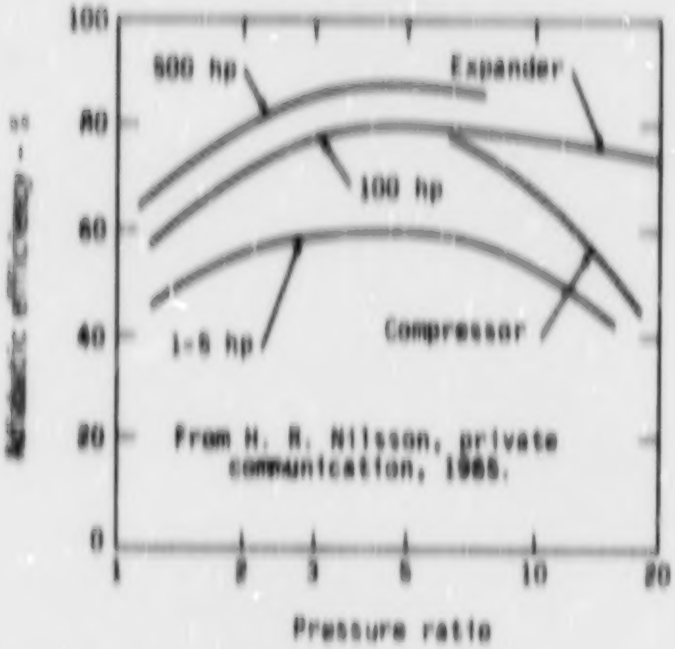


**Figure 6. Qualitative size and mode effects for screw machines.**

cause they will tend to relax somewhat with time as creep adjusts the rotor geometry very slightly to accommodate thermal expansion. Strain analysis of the rotor is further complicated by its geometry, stress concentrations, residual stresses, the natural variation of physical properties with temperature, and any compositional changes with rotor radius.

## MATERIALS REQUIREMENTS FOR HELICAL EXPANDERS

Each of the advanced coal-fired energy-conversion technologies spoken of in the beginning has unique materials requirements. The helical expander requires structural ceramics with predictable strength in the range of 2,500° F, adequate for rotating power-conversion machines. The debris tolerance advantage has already been mentioned. Also, such machines might run uncooled and thereby gain a performance advantage over cooled metal alloy counterparts.

One of the governing considerations in this machine performance tradeoff is illustrated in figure 8, which gives the strength-to-density ratio ($\sigma/\rho$) versus temperature. This is a governing criterion for rotating machines where the inertial stresses dominate. The dashed line at $80 \times 10^3$ in. represents a typical requirement for $\sigma/\rho$ for long life in axial-flow turbines. It is seen that the nickel-base alloys are limited to something like 1,600° F by this criterion. All present air-breathing gas turbines and the great part of those advanced models envisioned for the future are designed for the 1,600° F or lower metal temperature, with air or water cooling as required. This cooling is a loss to the cycle, reducing the gain from higher inlet gas temperature ($T_1$). It finally prevails in setting a particular limit for $T_1$ in the 2,200° F region.

Silicon nitride or silicon carbide are advocated for the helical expander construction material. They are seen to have a temperature advantage of 600° or 800° F over the nickel-base alloys for the $80 \times 10^3$ in. $\sigma/\rho$ criterion. Actually, as we have noted, the characteristic centrifugal stresses in the expander are much lower than for turbines. The resulting large margin on rotational stress would be used to accommodate thermal stresses and the brittle nature of these materials.

There are two other material regimes on the figure: graphite, which is another 800° F higher at the same $\sigma/\rho$ level, and the refractory alloys (Nb, Mo, Ta, W), which are in the same temperature range as the ceramic materials, but with about half of the $\sigma/\rho$, mostly because of their increased density. We dismiss both of these other material classes from the present expander material considerations because of the principal difficulty of taking

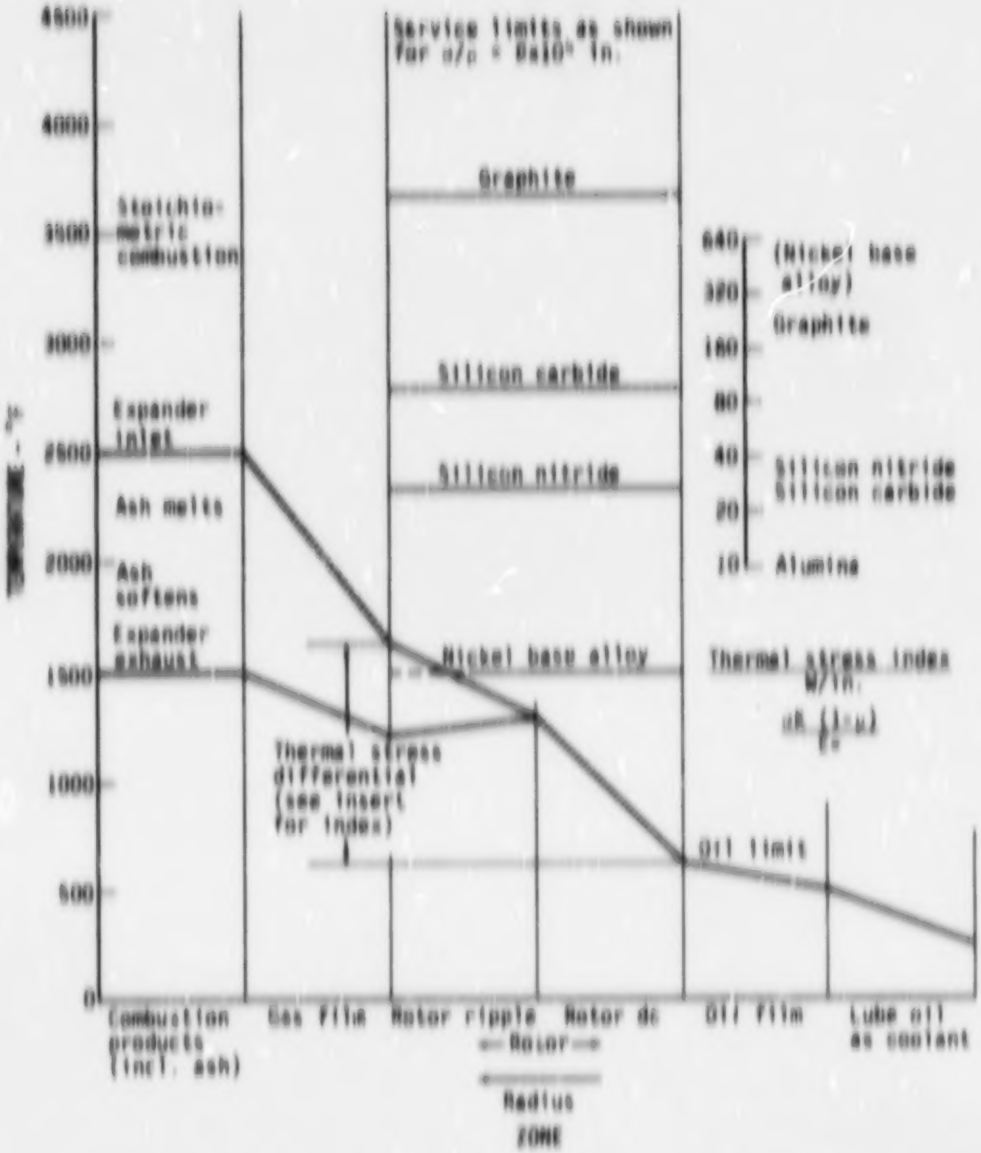
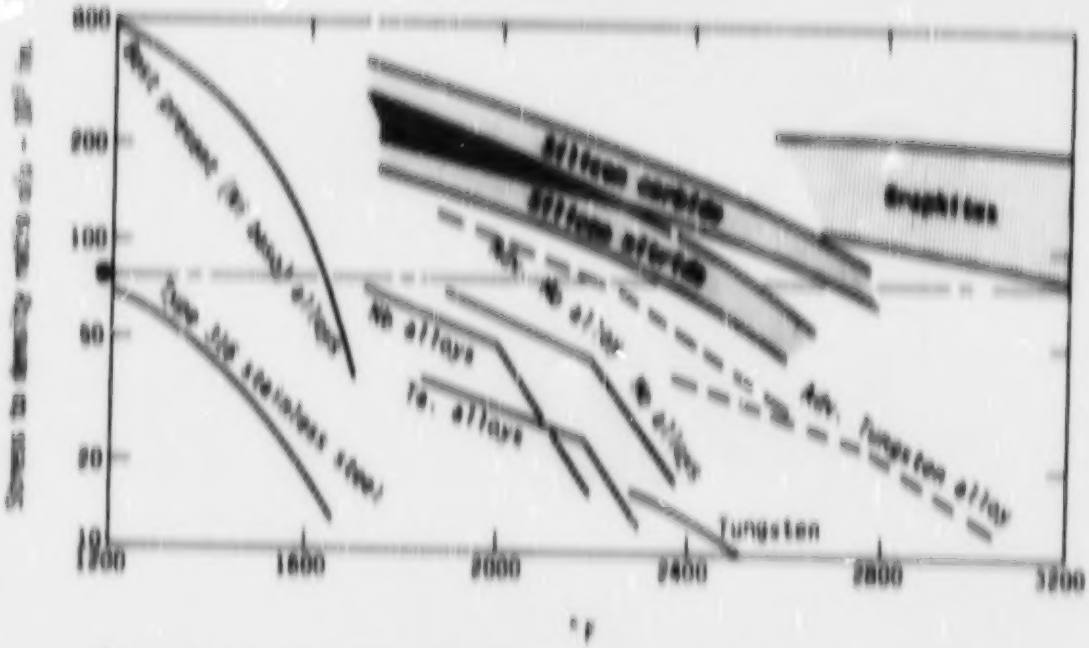


Figure 7. Schematic radial temperature profile for a screw expander under steady-state operating conditions with various temperature constraints.



● Minimum σ/ρ for axial gas turbine applications

Figure 8. Comparative σ/ρ data (temperature (°F) for 1 percent creep in 10,000 h).

care of the oxidation problem in coal-fired expanders. Graphite might be used if the combustion products could be kept everlastingly on the fuel-rich side and the ash content kept very low. Such a graphite system deserves separate attention, because of the very large working temperature advantage. Either alternate material might be used with inert gas as the working fluid, but that just transfers the oxidation problem to the heat exchanger and presumably reduces the peak cycle temperature.

We conclude, therefore, that the greatest advance is to be had in pursuing the development of ceramic machines, in particular the helical expander because it is best suited to the capabilities of ceramic materials now available or soon to be available.

There are a number of refractory compounds that can probably meet the primary mechanical and physical properties criteria (strength, stability, thermal strain tolerance, and compatibility with coal combustion products) for the helical expander. We will not dwell on all of the alternatives here, but we have considered most of the oxides, nitrides, carbides, and intermetallic compounds, especially of silicon, aluminum, beryllium, boron, titanium, and zirconium. We have made our initial selection of silicon nitride and silicon carbide, not only on the basis of attractive properties, but more especially on the basis of fabricability and economics. To our knowledge, only these two among the candidates with superior properties have been demonstrated to be practicable in the large sizes desired for the screw expander application, being at the same time economical and in plentiful supply. In the most elementary form, the fabrication process for both silicon nitride and silicon carbide parts involves powder consolidation to the rough final shape by any of a number of methods, bonding or partial conversion of the powders to give sufficient strength for green machining at high removal rates, and then final conversion. For both materials, the shrinkage on final conversion can be held to around 0.1 percent. Both would be finished by diamond wheel grinding. For each, there are maximum wall thickness levels based on tolerable times and temperature differences during reaction bonding and powder conversion. These levels are below the 1-ft or so half-thickness of characteristic features of full-scale rotors so that they would have to be significantly cored.

## EXPERIENCE WITH HIGH TEMPERATURE STRUCTURES AND MACHINES

We believe that two earlier experiences illustrate the potential for near term development of ceramic expanders.

The first experience with structural ceramics design came in connection with an advanced version of a 3,000° F gas-cooled nuclear reactor. A support was required for the 150-psi air-pressure-drop load across the reactor over a free span 36-in. in diameter. The design concept chosen was an arch configuration that eliminated tensile stress in the ceramic material. A seven-piece self-locking assembly shown in figure 9, was made of KT silicon carbide. Prototype elements were also fabricated of reaction-bonded silicon nitride in the approximate shape of a 24-in. hexagon with the same hole pattern as shown in figure 9. The silicon carbide assembly was proof tested in jet aircraft fuel combustion products at 2,700° F for over 50 h (ref. 8). The steady pressure-drop load was 150 psi. Cyclic loads at 10 to 60 Hz with a 50-psi amplitude were superimposed on the steady load. The structure was essentially unchanged by the test.

Later, with a challenge to design a machine for extracting power from a high-temperature gas-cooled reactor heat source, we thought about the best way to minimize the tensile stress problems inherently present someplace in any rotating power-conversion equipment. We wanted to make best use of ceramic and graphite materials having a statistical distribution of strength and low impact resistance. We chose the helical expander on the grounds which have been cited, namely, low tensile

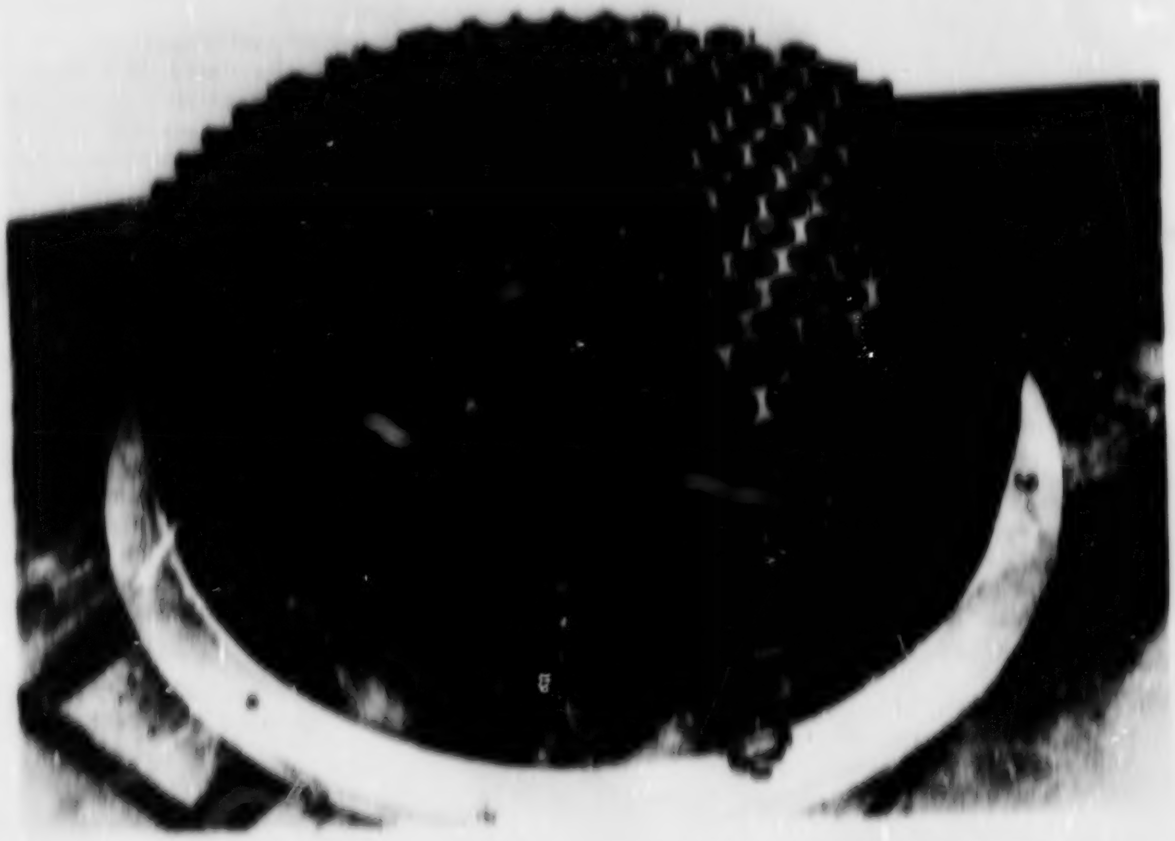


Figure 9. Ceramic support designed to withstand a 150-psi air-pressure-drop load over a free-span 36 in. in diameter.

stress and rugged geometry. A small helical expander and compressor demonstration machine was constructed of graphite for testing in argon at a temperature of 2,750° F. The rotors were 4 in. in diameter. A view of the rotors, a subassembly of the two helical machines, and the furnace setup is given in figure 10. The expander produced power from an electric generator on the outside of the furnace by means of a Brayton cycle. The system accomplished its 300-h demonstration mission successfully (ref. 6). A discussion of the brittle-materials criteria used in designing the machines is given in reference 7. A follow-on study considered the performance of a high-temperature reactor power plant using the graphite expander (ref. 8).

## CERAMIC HELICAL EXPANDER MATERIALS IN COAL COMBUSTION PRODUCTS

The combustion of coal produces $CO_2$, steam, ash, unburned char, and many other substances. Coal combustion products have proven to be corrosive for a wide variety of conventional metal and ceramic materials. Silicon nitride and silicon carbide have not been tested in this regard. They have demonstrated remarkable corrosion and thermal shock resistance in jet fuel combustion products flowing at Mach 1. In one series of tests, they were heated at 2,100° F for 1 h and then cooled for 5 min (with the cycle repeated 100 times) without failure (ref. 9).

We have noted that ash velocities in the expander are relatively low, i.e., in the vicinity of the rotor tip speed. The kinetic energy will therefore be down by an order of magnitude or so compared to that of ash in turbines. The effects of ash flow on ceramic materials are expected to be substantially different than on metals.

We have initiated a series of experiments to investigate the rate of erosion and corrosion of silicon nitride and silicon carbide in flowing coal combustion products and ash. The effects of the gas composition, ash temperature, and the temperature of the material will be tested. Other variables to be investigated are test material composition, ash composition, ash particle size, and the angle of impact of the ash. Erosion by particles in a stream is the subject of a number of recent investigations (refs. 10,11).

Coal-fired boilers are subjected to fouling from condensation of various combustion products. Control of boiler fouling is a well-developed art at conventional plants. It has been learned that there can be a guide to the control of fouling in a ceramic expander. Helical expanders have been operated in geothermal brines where fouling is a severe problem. Salt deposits did form on the expander rotors, but they "wore in" to very low clearances without detrimental effects (ref. 12).

## THE HELICAL EXPANDER COMBINED CYCLE

A block diagram of the helical expander combined cycle is shown in figure 11. The cycle starts with a state-of-the-art axial-flow bladed compressor with a compression ratio of 10 and an adiabatic efficiency of 88 percent, supplying air to a coal burner.

We presume for the figure that the fuel preparation and burner boxes together would include some emission control features. Actually, we are investigating the two-stage fluidized bed burner (refs. 13,14,15), which has the potential for good ash scavenging in the bed. The cyclone burner is also to be considered. It is in use today in large coal-fired plants and removes 90 percent of the ash as molten slag directly in the burner. Its use to date has been limited to coals containing low-melting ash. The relatively low combustion temperature should not cause any $NO_x$ problems. We think of exhaust gas scrubbing for final $SO_2$ control and precipitators for final ash control as required.

Hot gases with some ash carryover would be supplied to the expander at 9 atm and 2,450° F. We project at this time that a reasonable maximum size for a ceramic rotor is about 5 or 6 ft, and two units of that size should deliver about 80 MW net electrical output for the conditions shown. Such expanders may have an adiabatic efficiency in the high 80 percent range according to extrapolations of figures 5 and 6. We entered an overall expander efficiency of 75 percent in the calculations so as to allow a margin for the mechanical efficiency of bearings, seals, and timing gears.

The expander exhaust goes to a convection-dominated boiler to raise steam for a standard steam cycle. Matching the expander exhaust energy to the requirements for final feedwater heating, evaporation, superheating, and reheating of the steam gives a steam cycle output of about 100 MW. The pinch temperature or the minimum difference between hot gas and steam cycle states was presumed to be 100° F. An artist's depiction of this system is shown in figure 12, with a two-stage fluidized bed burner and the topping cycle compressor operating on the steam turbine shaft for better rotational speed matching.

Based on figure 11, the combined-cycle efficiency from burner input to steam cycle rejection is,

$$\eta_0 = \frac{\text{Input} - \text{Reject}}{\text{Input}}$$

$$= \frac{\text{[illegible]}}{1,\text{[illegible]}}$$

$$= 0.53$$

External drive assembly

Graphite compressor-expander case in furnace

Graphite rotors

Figure 10. Views of a graphite helical expander and compressor test assembly ran successfully at 14,000 rpm for 300 h at 2,750° F in an argon atmosphere.

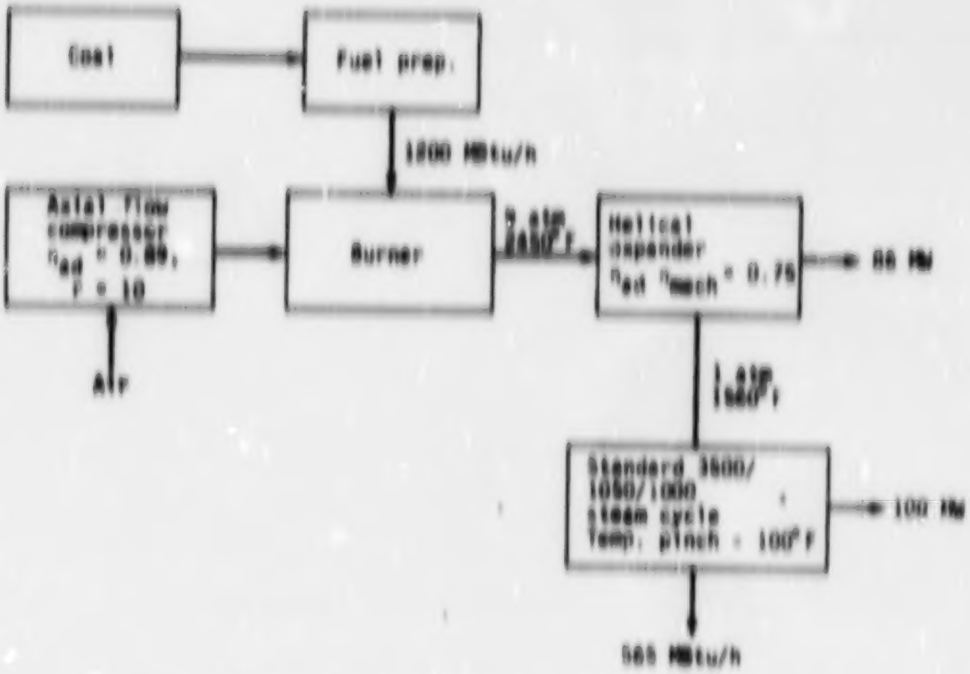


**Figure 11. Block diagram of the helical expander combined cycle (efficiency = 1 − $\left(\frac{565}{1200}\right)$ = 0.53).**

This is well into the 60 percent range that we postulated in the introduction.

## CONCLUDING REMARKS

We are currently underway on the necessary materials development and expander design studies for this system. The near-term goal is construction of a 70- to 120-kW expander operating at an inlet gas temperature of 2,500° F for performance and compatibility studies. Favorable findings will lead to construction of a 6- to 10-MW, 24-in., intermediate version of the expander and later of a full-size 60-MW machine.

We intend to emphasize high efficiency and the ability to operate directly on coal combustion products.

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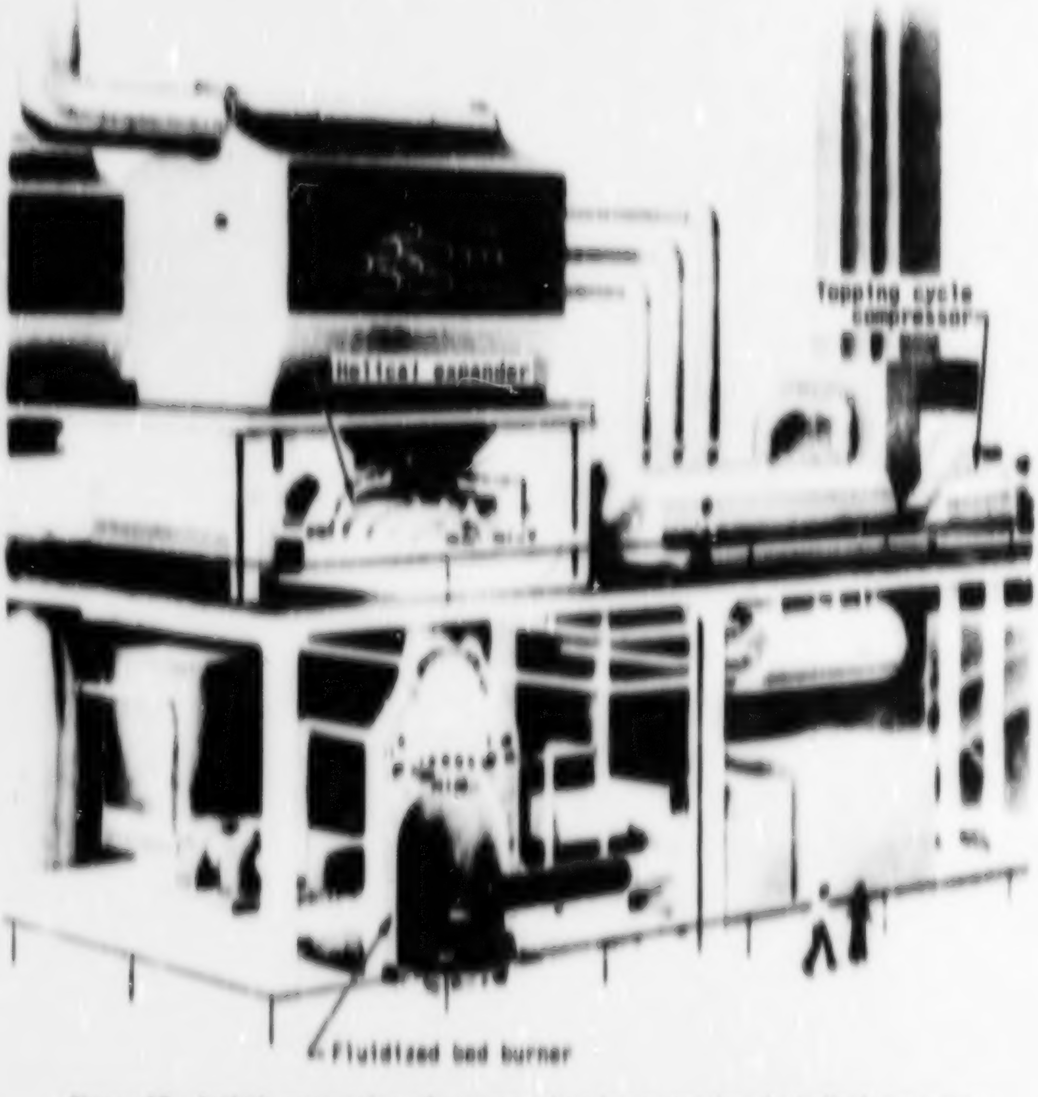
Topping cycle compressor
Helical expander
Fluidized bed burner

Figure 12. Artist's conception of a power plant incorporating the helical expander in a combined cycle.

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# BALANCE OF PLANT POWER REQUIREMENTS FOR ADVANCED POWER SYSTEMS

Irving L. Chait[1]

## *Abstract*

*The growth in unit size of central station steam power plants in the last 20 years has been accompanied by a parallel and even more rapid growth in the auxiliary power required to operate the unit. From a nominal 4 to 6 percent of rating, onsite auxiliary power has steadily increased and, today, often takes 10 to 12 percent of the plant's output. The increases have resulted from a combination of environmental regulations and more severe operating conditions.*

*Many proposed advanced power-conversion plants include, in addition to the usual auxiliaries, process equipment not found in today's plants. The power demand of all these auxiliaries may exceed the totals of present-day plants and must be included in determining the overall performance of advanced power systems—particularly when comparisons are made among such systems.*

*To achieve the efficiencies and environmental acceptance desired, power plants using advanced power conversion systems—such as MHD generation, fuel cells, advanced steam and gas turbines in various combinations, fusion reactors, and solar collectors—are combined with topping and bottoming plants, which look very much like present-day plants. For equally cogent reasons, they are integrated with coal gasification and fuel-conditioning processes, cryogenic refrigeration, magnets, oxygen plants, scrubbing systems, seed recovery, and similar energy-consuming auxiliaries. The power load imposed by these additional processes may significantly reduce the overall plant thermal efficiency.*

*From the viewpoint of energy and environment conservation, considerable benefit can be achieved by optimizing the balance-of-plant systems. Efforts for such improvements should proceed on parallel paths with, and at the same pace as, the efforts being made in developing the main advanced power-conversion systems.*

## INTRODUCTION

Modern central-station, steam power plants have grown in unit size over the years, and so has the auxiliary equipment required to operate them. The major power demand in the balance-of-plant systems in coal-fired plants has always come from the draft fans, circulating water pumps for condensing exhaust steam, coal conditioning and handling equipment, soot-blowing systems, and condensate pumps. Boiler feed pumps, the largest single service requirement in steam electric power plants, are usually turbine driven because of the economic benefits, increased net output of kilowatts, and about a 60 Btu/kWh improvement in heat rate.

Connected and operating electric power demands of the auxiliaries of typical fossil and nuclear plants are shown in tables 1 and 2. The operating loads are about 65 percent of the connected load in the fossil plant and 70 percent in the nuclear plant. Table 1 indicates that the auxiliary power operating load at design capability for coal-fired plant is 7.6 percent of plant gross rating. This plant fires a low sulfur coal and has no scrubber. A scrubber would add about 50 percent to the auxiliary load. Table 2 indicates that the auxiliary power operating power demand for a nuclear plant is 4.7 percent of the generator rating. Steam bottoming plants for advanced power conversion systems will have many auxiliaries similar to those shown in tables 1 and 2.

The growth of the utility industry has been paralleled by the proliferation of regulations requiring the addition of new auxiliaries to meet the environmental criteria. Electrostatic precipitators, scrubbers, cooling towers, waste treatment systems, water management and other environmentally related facilities are becoming as ubiquitous in power stations as fans and water pumps. Simultaneously, operating conditions have become more severe, and lower quality fuel has been increasingly used. Thus, from a level of about 4 percent of gross output for the onsite usage of power, the auxiliary power of present-day plants now often amounts to 10 to 12 percent (ref. 1). For a 1,000-MW (net) plant with an heat rate of 10,000 Btu/kWh, as the auxiliary power increases from 4 to 10 percent, the thermal efficiency decreases from 34 to 30 percent. A loss of efficiency of this magnitude wipes out decades of developments and improvements in power plant technology.

Many advanced power conversion plants—particularly the ones in which fossil fuels are required, such as advanced steam and gas turbines, MHD, fuel cells, combined cycles, etc.—will, of necessity, be integrated with process technologies not common in present-day power plants. These technologies include fluid bed furnaces,

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Table 1. Auxiliary power requirements (motors 25 hp or larger only) for 420-MW coal-fired steam turbine generator plant

| | Connected load (hp) | Operating load (hp) |
|---|---|---|
| Forced draft fans | 16,000 | 10,600 |
| Induced draft fans | 12,000 | 9,800 |
| H.P. service water pumps | 2,000 | 675 |
| Boiler startup pump | 700 | - |
| Gas recirculating fans | 6,000 | 5,520 |
| Low-pressure service water pumps | 900 | 405 |
| Closed cooling water LP pumps | 800 | 360 |
| Condensate pump | 1,600 | 711 |
| Boiler circulating pumps | 6,200 | 5,024 |
| Isolated phase bus blower | 120 | 54 |
| Stator cooling water pump | 80 | 36 |
| Auxiliary oil pump | 60 | - |
| Control air compressors | 250 | 113 |
| Condenser air exhauster | 250 | 113 |
| Service air compressor | 200 | 180 |
| Seal oil reheater | 27 (kW) | - |
| Carbon dioxide heater | 36 (kW) | - |
| Glycol pumps | 250 | 113 |
| Motor-generator set | 120 | - |
| Ash pit sump pump | 400 | 180 |
| Gas recirc. fan turning gear | 150 | 68 |
| Closed cooling water booster | 50 | 23 |
| HVAC supply fan | 100 | 90 |
| Ventilating supply fans | 300 | 270 |
| Roof exhausters | 150 | 138 |
| Prec. area fan | 100 | 90 |
| Circulating water pumps | 2,000 | 1,732 |
| Screen wash pumps | 200 | 180 |
| Fuel conditioners | 1,800 | 1,200 |
| Ignition oil pumps | 100 | - |
| Crusher | 500 | 450 |
| Conveyer | 905 | 725 |
| Cyclones | 350 | 262 |
| Precipitator | 3,155 | 1,276 |
| Hydraulic fluid pump | 300 | 180 |
| Heater drain pump | 125 | 113 |
| Seal air blower | 40 | 36 |
| Total hp | 57,292 | 40,717 |
| $kW = \frac{hp \times 0.746}{0.95}$ | 44,989 | 31,974 |
| Percent rating 420 MW | 10.7 | 7.6 |

Table 2. Auxiliary power requirements (motors 25 hp or larger only) for 1,100-MW nuclear power plant

| | Connected load (kVA) | Operating load (kVA) |
|---|---|---|
| Condensate pumps | 3,315 | 2,210 |
| Condensate booster pumps | 7,725 | 5,160 |
| Circulating water pumps | 13,211 | 13,211 |
| Plant service water pumps | 2,678 | 1,339 |
| High-pressure core spray pump | 2,588 | - |
| 480-V auxiliaries | 225 | 75 |
| Reactor recirculating pumps | 15,194 | 15,194 |
| Cooling tower fans | 10,000 | 7,318 |
| Low-pressure core spray pumps | 1,330 | - |
| Reactor HR pump | 2,175 | - |
| Standby service water pumps | 3,060 | - |
| Makeup water pumps | 2,868 | 1,434 |
| CRD pumps | 340 | 276 |
| Substation auxiliaries[a] | 18,000 | 11,600 |
| Total kVA | 82,709 | 57,817 |
| Percent rating (1,230,000 kVA) | 6.7 | 4.7 |

coal gasification or liquefaction plants, cryogenic refrigeration for superconducting leads and magnets, scrubbers, and seed and sulfur recovery processes. The new processes, superimposed on most of the "old" auxiliary systems, will undoubtedly increase the fraction of power absorbed by the auxiliary systems. If more than 10 to 12 percent of all power generated is to be used inside the power plant before it is transmitted to any customer, the savings in energy expected by the application of some of the higher efficiency, advanced conversion systems may be disappointing. Increases in auxiliary power not only result in a requirement for larger installed unit capability but also reduce the net efficiency of a plant. To arrive at realistic levels of efficiency attainable by the various combinations of advanced power conversion systems and their associated process technologies, a consistent and complete determination of balance-of-plant requirements is necessary whenever a complete plant is considered.

The limits of the balance-of-plant systems for an advanced power conversion cycle plant are necessarily somewhat vague. Even in present-day plants, the boundaries may be defined differently, depending upon the purpose for which they are established. All the energy expended—in gathering, processing, treating, transporting, generating, converting, and transmitting a natural resource to the ultimate consumer of the heat, light, and power—should be included if the true net power available from a plant is to be determined. If, in addition to cost factors, energy conservation and environmental benefits are to be considered primary desiderata for advanced power conversion system plans, they must be evaluated on as equivalent and comparable bases as practicable. The auxiliary systems for the advanced power systems discussed hereinafter are indicative of the magnitude only of their onsite power requirements.

## MAGNETOHYDRODYNAMIC POWER PLANTS

The major auxiliaries in magnetohydrodynamic power-generating plants are the air compressor, cryogenic refrigeration plants for superconducting magnets, oxygen production plant for enrichment (if used), gas cleanup (if not in the power cycle), seed recovery plus all the auxiliaries for coal handling and preparation for a coal-fired plant and a bottoming steam or gas turbine plant (whichever is utilized). Such components as air heaters and combustors are not included in balance-of-plant systems as used in this paper.

Projected thermal efficiencies of first generation central station MHD power plants are in the 40-50 percent range. One of the cases studied for a 1,000 MW (net) total MHD steam power plant (ref. 2) assumes that air is preheated to 3,000° F and that a 6-Tesla superconducting magnet is used with the generator. Fifty percent of the output is produced by the MHD generator and 50 percent by a bottoming steam plant. The air compressor requires 167 MW, steam plant auxiliary power is taken as 4 percent of the gross steam plant output, and inverter losses as 3 percent of MHD generator output, for a total of about 16 percent of gross output. Power or energy requirements of the seed recovery, superconducting magnet cooling system or gas cleanup system are not listed separately. The paper also discusses the potential improvement of efficiency if oxygen replaces air in the combustor. The oxygen compressors alone require up to 16 percent of the total plant output. Such an oxygen plant requires 13 kW per 1,000 scfh, or 0.15 kW/lb/hr of oxygen produced at essentially atmospheric pressure. If a higher pressure, say 30 atmospheres, is required, the oxygen plant will require 16 kW per 1,000 scfh or 0.2 kW/lb/hr.

The refrigeration system load during steady-state operation of a superconducting magnet is relatively low; the initial cooldown sets the capability requirements of the refrigeration plant. For a 1,000 MW MHD plant, the magnet power supply would require about 5,000 kW, the compressor 1,150 kW, and cold box about 50 kW—or a total of less than 1 percent of power rating.

Seed recovery technology for MHD generators is one auxiliary system that requires greater definition. Coal ash and seed will be mixed. Processes that can separate and recover the seed with the required high-process efficiency are not yet developed. One proffered scheme for potassium seed recovery is shown in figure 1. It indicates the possible sequence of steps, including one in which a formate compound is formed as an intermediate compound, followed by filtering, crystallizing, evaporation, and calcining. For a 2,000 MW (total) MHD steam plant, the equivalent of 265 MW of heat is required in the evaporator and an additional 180 MW for the crystallizer—based on a 7,000 Btu/kWhr plant heat rate. It is apparent that this energy must be recovered if the process is to be considered viable. The recovery of low-temperature steam is not always practical in a power station. Another seed recovery system for an 800-MW plant is described in reference 3. The method described is similar and the power usage appears to be of the same order of magnitude as required for the formate method.

Electrostatic precipitators, scrubbers, and other gas cleanup components in the MHD plant have large power demands. Scrubbers are discussed hereinafter.

Overall, the auxiliary systems associated with magnetohydrodynamic plants will require further development along with the power cycle, not only to perfect the technology and reduce capital costs, but to reduce the power required by these systems and the attendant costs and energy losses.

## FUEL CONVERSION AS AN AUXILIARY SYSTEM

The viability of many advanced power systems for power station applications is largely dependent upon the development of suitable fuel converted from coal. In particular, fuel cells and advanced gas turbines, among the advanced power technologies, are linked with the world's petroleum fuel problems. Therefore, large utility stations of the future will be integrated frequently with a coal conversion process. The coal conversion system will, for the most part, be independent of the generating plant even though it may be partially interconnected thermodynamically with the power cycle.

For example, the molten carbonate fuel cell is considered (refs. 4,8) to be one type, which has the best potential for application to large power plants. Molten carbonate cells operate at 500°-700° C temperature and at about 10 atmospheres for long time periods—conditions which may be compatible with many coal conversion processes. The molten carbonate electrolyte is compatible with carbon dioxide, thereby easing the fuel conditioning problems—which were encountered with many types of fuel cells. Also, the electrodes for these cells do not require the costly catalysts that are mandatory in low-temperature fuel cells. It is expected that it will be possible to tailor gas quality to the fuel cell requirements. The fuel cell exhaust can be recycled, as in figure 2, to maintain the coal steam shift reaction, or the exhaust can be used in a steam or gas turbine bottoming plant, as in figure 3. Nevertheless, the need to reduce the levels of particulates, sulfur, and $NO_x$ will still be there but shifted to the gasification plant.

The Kopper-Totzek process (ref. 9) is an example of an intermediate-Btu (300 Btu/lb gas) process that can be integrated with fossil-fueled advanced power systems. In one study of a 1,000 MW plant, about 17 modules will be required (ref. 6). The plant will convert about 14,450 tons of coal per day and requires an equal amount of steam and 11,600 tons of oxygen per day. Such an oxygen plant requires about 190,000 kW or 13 kW per ton of coal per day. The steam requirements of $1.2 \times 10^6$ lb/hr if of central power plant size. Scrubbing for desulfurization and particulate removal, sulfur recovery, ash handling, and other conditions may be necessary to obtain a suitably "clean" fuel. Use of air

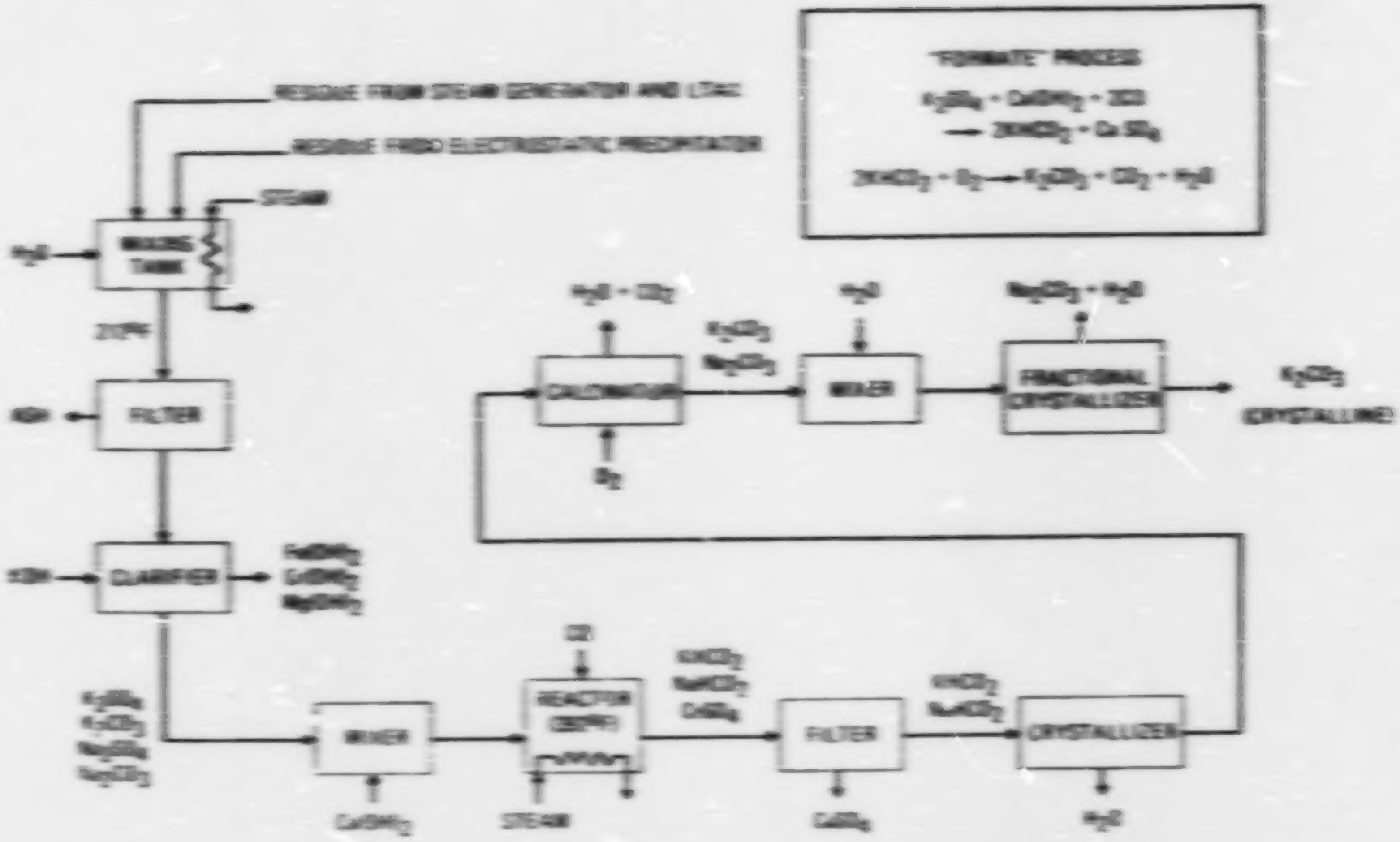
"FORMATE" PROCESS
$K_2SO_4 + Ca(OH)_2 + 2CO \rightarrow 2KHCO_2 + CaSO_4$
$2KHCO_2 + O_2 \rightarrow K_2CO_3 + CO_2 + H_2O$
RESIDUE FROM STEAM GENERATOR AND
RESIDUE FROM ELECTROSTATIC PRECIPITATOR
STEAM
$H_2O$
MIXING TANK
212°F
FILTER
ASH
KOH
CLARIFIER
$Fe(OH)_3$
$Ca(OH)_2$
$Mg(OH)_2$
$K_2SO_4$
$K_2CO_3$
$Na_2SO_4$
$Na_2CO_3$
MIXER
$Ca(OH)_2$
CO
REACTOR
STEAM
$KHCO_2$
$NaHCO_2$
$CaSO_4$
FILTER
$CaSO_4$
$KHCO_2$
$NaHCO_2$
CRYSTALLIZER
$H_2O$
$H_2O + CO_2$
CALCINATOR
$O_2$
$K_2CO_3$
$Na_2CO_3$
$H_2O$
MIXER
$Na_2CO_3 + H_2O$
FRACTIONAL CRYSTALLIZER
$K_2CO_3$
(CRYSTALLINE)

Figure 1. Process flow chart for seed conversion system.

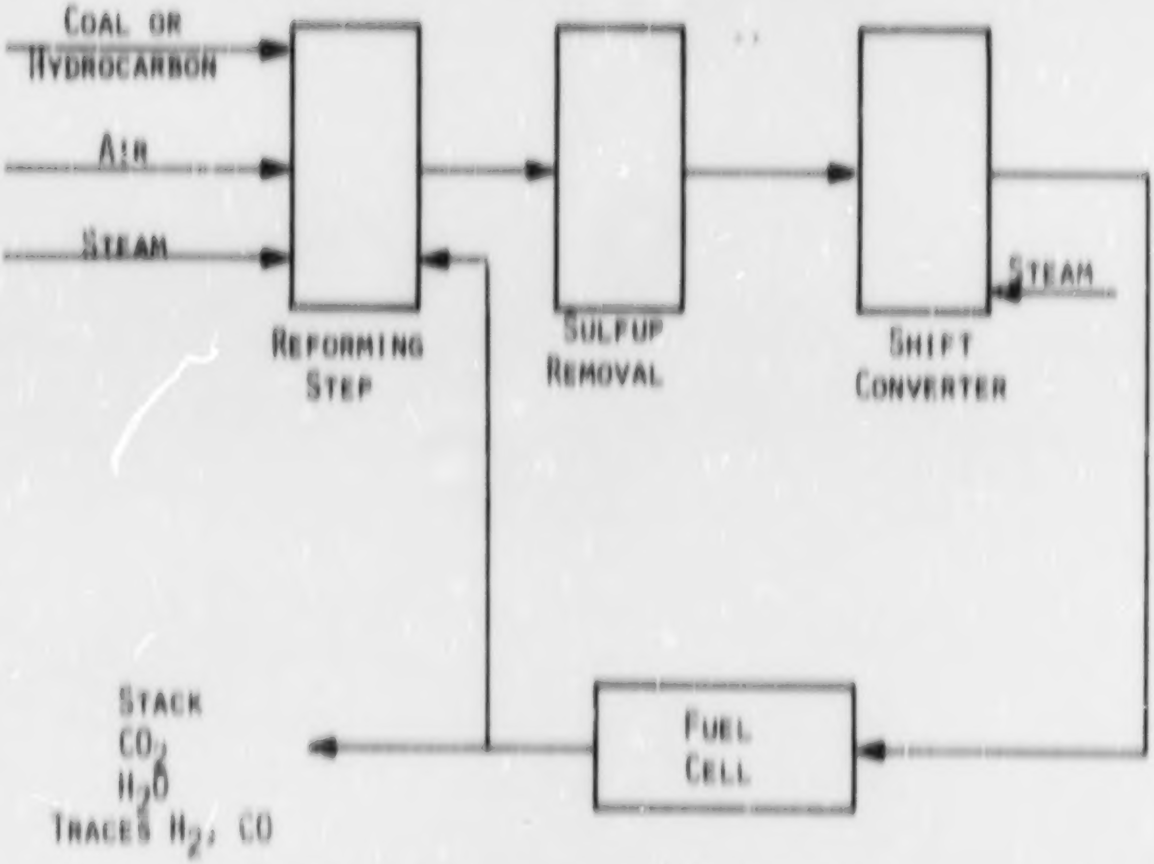

Figure 2. Fuel cell with gasification and shift conversion.

instead of oxygen, which is considered feasible, probably will not reduce the energy requirements.

A second study (refs. 7,8) of a 1,000-MW (nominal) integrated Lurgi low-Btu gasification and combined gas-steam turbine generating plant estimates that the fuel conversion plant will require 83 MW. On the basis of 6,670 tons of coal per day, the auxiliary requirements are 12.4 kW per ton of coal, which is close to the Koppers-Totzek plant requirements. The integrated combined plant thermal efficiency is expected to drop to 35 percent based on the electrical plant efficiency of 45 percent.

A 10,000 tons/day coal liquefaction plant study (ref. 9) estimates that the electric power plant requirements will be about 6 kW per ton of coal per day and that an additional $184.5 \times 10^6$ Btu/hr of energy in the form of fuel will be burned in the process. A liquefaction plant will not necessarily be integrated with the electric generating plant.

The coal conversion plants will undoubtedly result in a large increase in auxiliary power and, therefore, adversely affect energy conservation. From the environmental conservation viewpoint, many of the polluting sources of coal-fired power plants, such as sulfur, $NO_x$, hydrocarbons, and particulates, will be transferred to the coal conversion plant. The goals of less dependence on oil for power generation and better control of environmental effects may often be in conflict with the goals of energy conservation. The energy losses incurred by converting of one fuel into a more environmentally acceptable one is one price paid for energy independence.

## SCRUBBERS AND OTHER CLEANUP DEVICES

Advanced power systems such as MHD, coal conversion plants integrated with fuel cells, gas turbines, and steam turbines will require scrubbers, desulfurization

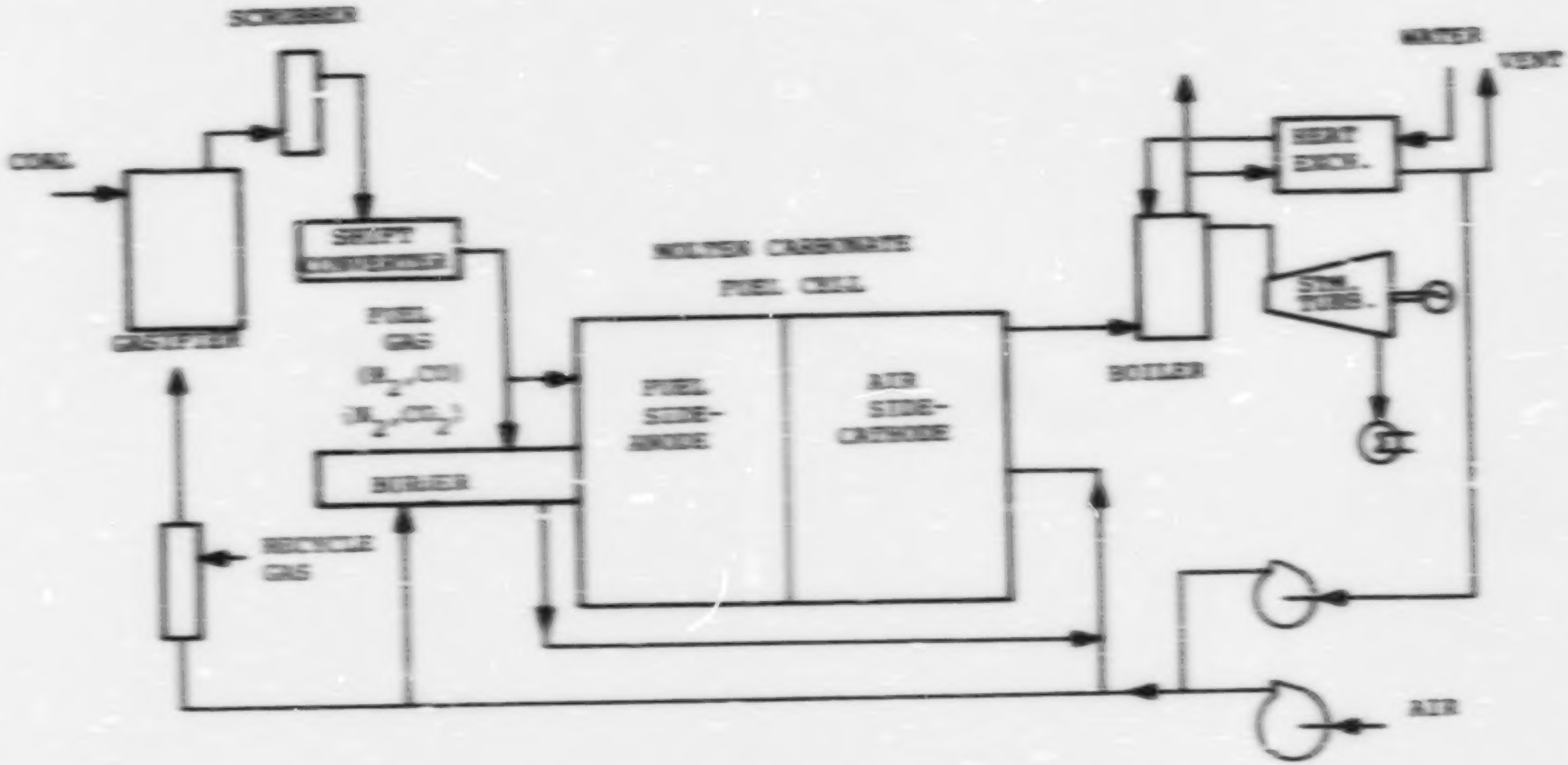
SCRUBBER
COAL
GASIFIER
SHIFT CONVERTER
FUEL GAS
$(H_2,CO)$
$(H_2,CO_2)$
BURNER
RECYCLE GAS
MOLTEN CARBONATE FUEL CELL
FUEL SIDE-ANODE
AIR SIDE-CATHODE
BOILER
HEAT EXCH.
WATER
VENT
STM. TURB.
AIR

Figure 3. Molten carbonate fuel cell system with gasification and bottoming plants.

processes, or other particulate removal processes. One reason why scrubbers have been particularly vexatious to a few large power utilities is that scrubbing systems often increase in-plant auxiliary power requirements by 30 to 50 percent. Reports of scrubber performance (refs. 10,11,12) indicate that the scrubbing systems can consume up to 5 percent of the power produced by a unit. As shown in table 1, electrostatic precipitators are among the users of large amounts of power, but require considerably less than is consumed by scrubbers.

## SOLAR AND FUSION

The principal auxiliary power demand of solar generating plants is for pumping of the circulating fluid. Pumping power requirements for a 200-MW plant using concentrating parabolic trough collectors integrated with a steam plant have been calculated to be about 0.4 percent of the power generated in the integrated steam plant (ref. 13). The main heat loss through the walls of the circulating fluid system is given as 1.8 percent of kilowatts available from the collectors.

Fusion reactors have yet to demonstrate all conditions for self-sustaining operation with a net payoff. Many types of power-generating systems have been suggested as bottoming plants. The parasitic and auxiliary power requirements of fusion plants are expected to result in a negative power output for many years to come. The first generation Princeton reference design (ref. 14) for a 2,000 MW Tokamak fusion power plant projects a power output of 2,405 MW(e) gross, with 15.6 percent (or 375 MW) required for station service and 2,030 MW net—and an overall plant thermal efficiency of 38 percent.

## SUMMARY

The paper shows, by example, that in many advanced power systems proposed for utility power applications, the balance-of-plant systems will require upwards of 10 percent of the power generated. In addition, substantial amounts of energy in the form of steam, additional fuel, or other sources will be required. These onsite requirements are partly the result of the effort to safeguard the environment, partly the result of the need to move away from the use of petroleum fuels, and partly due to the lower level of concern usually given to auxiliary systems than to main power cycle systems.

Since many of the auxiliary systems require no fundamentally new technology, they are taken for granted and not given enough consideration in advanced power conversion system work. However, as they will consume a considerable amount of the energy produced, more attention should be focused on them. In some cases, improvements in the auxiliary technologies will result in as much benefit as may be gained in improved efficiency of the main cycle of the advanced power plant.

There appears to be a real possibility for a satisfactory payoff to justify increased study and effort to develop the balance-of-plant auxiliary systems so that when the new advanced systems arrive, all the auxiliaries will match them in maturity and in the maximum possible energy and environment conservation. The goals of energy and environmental conservation will be achieved with these advanced systems only if sufficiently high plant efficiencies are attained so that they will more than just compensate for the increased auxiliary and parasitic losses.

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5 November 1975

### Session V:

# RESIDENTIAL AND COMMERCIAL ENERGY SYSTEMS

**Robert Rosenberg, Ph.D.**[*]
**Session Chairman**

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# THE POTENTIAL ROLE OF SOLAR ENERGY IN CONSERVATION FOR BUILDING HEATING AND COOLING

Frank R. Biancardi and Maurice D. Meader*

*Abstract*

*A number of solar collector configurations and air conditioning subsystems are being investigated for use in solar-powered building, heating, and cooling applications. The pertinent characteristics and operating features of representative flat-plate and focusing-type collectors as well as typical Rankine-cycle, absorption, and desiccant air conditioning systems are briefly described. Estimates of the energy savings possible for the remainder of this century, with widespread utilization of solar-powered systems, are also presented, based on ERDA data.*

*As part of the NSF/ERDA program to explore new solar-powered systems, a Rankine-cycle turbocompressor air conditioning and heating system has been designed, fabricated, and tested. The design features of the system are described and results obtained during the performance testing of the system are presented.*

*The test results provide a convincing demonstration of the feasibility of operating a Rankine-cycle turbocompressor air conditioning and heating system at system temperature levels consistent with present-day, flat-plate solar collectors. During the testing of the demonstration system, more than 4 tons of cooling and in excess of 60 hours of safe, reliable operation were obtained. Most significant was the operation of the system over a range of turbine inlet temperatures from approximately 185° F to more than 215° F, during which the system performance goals were met or exceeded.*

## INTRODUCTION

Approximately one-quarter of the energy consumed annually in the United States is used for building hot water, heating, and cooling. Since systems to provide these functions do not require high-temperature heat input for successful operation, energy from the sun could be converted into usable low-temperature energy to replace a significant fraction of our valuable fossil fuels presently used for heating and cooling. ERDA believes (table 1) that solar technology for building heating and cooling offers the potential for supplying about 1.5 percent (2.0 Q) in 2000 and by 2020, as much as 10 percent (15 Q) of the Nation's future energy needs if costs of collecting and utilizing solar energy can be reduced substantially. The annual savings associated with the conservation of fossil fuels brought about by solar energy utilization thus could approach $35 billion dollars even at today's energy prices.

Although most of the technology involved in direct thermal applications is more advanced than for other solar technologies, substantial research and development is still required if the full potential for solar heating and cooling for buildings is to be realized. A brief review of the major subsystems required for building solar heating and cooling applications is presented before describing work performed at UTRC under NSF/ERDA sponsorship on a unique low-temperature, Rankine-cycle heat pump system.

## SOLAR BUILDING SYSTEMS

A typical system for the solar heating and cooling of buildings consists of a collector exposed to the sun's radiation, a heat transfer fluid (liquid or air) which carries the collected energy to the points of storage or use, thermal storage devices, cooling or air conditioning devices, and air handling systems for distributing conditioned air within the building spaces, and an auxiliary energy source (fig. 1). Provisions may be made for domestic hot water; and appropriate pipes, ducts, pumps, fans, heat exchangers, and controls are included as required. However, the critical system subsystems are the solar collector, thermal storage, and air conditioner.

### *Solar Collector*

A solar collector consists conceptually of (1) a radiation transmitting-shielding system designed to pass short wavelength energy from the sun and atmosphere to a collecting surface, while minimizing back radiation and convection heat losses, (2) a highly absorbing surface to accept the radiation, and (3) an insulated heat exchanger system to transfer the energy to some working fluid for transport to the energy storage or utilization system. The flat-plate collector with one or more parallel glass plates spaced approximately 1 inch apart, placed before an insulated absorbing black surface has been widely used. The black surface is generally a coated metal plate which is integrated into the heat exchanger.

Variables which affect collector performance include collector tilt angle from the horizon, type and

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Table 1. Estimates of the energy and fuels to be supplied in the United States by solar energy: direct thermal applications (in units of Q=Quads=$10^{15}$ Btu per year) (ref. 1)

| | 1985 | 2000 | 2020 |
|---|---|---|---|
| Heating and cooling | 0.15 | 2.0 | 15 |
| Agricultural applications | 0.03 | 0.6 | 3 |
| Industrial applications | 0.02 | 0.4 | 2 |
| Total | 0.2 | 3 | 20 |
| Total projected U.S. energy demand | 100 | 150 | 180 |

number of back radiation shields, absorber surface material and coating, heat exchange configuration, insulation, and seals. Unfortunately, present-day, flat-plate collectors have typical performance characteristics as shown in figure 2 and thus are not capable of providing heated fluids above 200° F while capturing a large fraction of the incident solar energy. Medium concentration collectors in which the incident energy is focused on collection surfaces have the capability of providing fluid temperatures of 300° to 500° F with reasonable efficiencies. These collectors, however, require movement of the reflector or collector surfaces but simple, reliable methods of providing these features are being investigated. Extensive research and development efforts supported by NSF and ERDA are also underway on both types of collectors to reduce costs and improve collection efficiency (ref. 2).

*Energy Storage*

The design of the energy storage system involves a selection of both the storage medium and system capacity. For sensible heat storage type materials, water is attractive on an energy per unit volume basis. Also of interest are phase change materials such as noncongruent melting point salts which can store chemical energy and/or operate at higher temperatures than water. Some difficulties exist with their use in the form of supercooling and segregation in the storage tank. The capacity of the storage system is a function largely of economics. Work to date has suggested that it should be proportional to the solar collector area at a value of 10 to 15 lb of water (or its heat capacity equivalent for a different medial per square foot of collector area.

To make the most effective use of both the solar collector and the air conditioning unit, the storage sys-

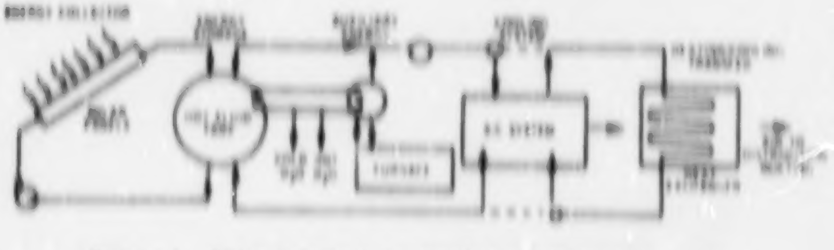

Figure 1. Solar-powered heating/air conditioning system.

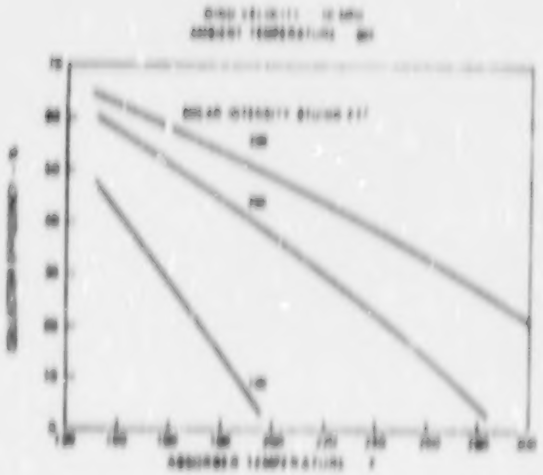

Figure 2. Typical solar collector efficiency.

tem should be operated so that it enhances thermal stratification. During winter operation, the coldest water is removed from the storage tank bottom, heated in the solar collector, and ideally returned to the tank at a level where it can mix without turbulence with fluid of the same temperature. Similarly, the cooling cycle will work most efficiently with the hottest fluid available. The piping, valving, and pumping arrangements necessary to achieve these objectives can become complicated.

For combined heating/air conditioning operation, there are some advantages to physically splitting the thermal storage into two sections or separate tanks. During the heating season, the two tanks could be operated at different temperature levels to improve collector performance. During summer operation, one tank could be operated hot and the other cold. Then, any excess refrigeration capacity when the air conditioning load is low could be used to chill water. (The use of a phase change storage material would be particularly attractive when operating in this mode.) The dual system would also allow a maximum of flexibility during seasonal changeovers. Programs are being supported by NSF/ERDA to investigate improved energy storage systems.

### *Air Conditioner*

The cooling process which is utilized in any thermally driven air conditioning system must be simple and reliable and result in high system operating efficiency in order to minimize overall systems cost and maximize the utilization of solar energy. If these requirements are not met, the collector, energy storage, and air conditioner are likely to become large and excessively costly, and the entire system will become uneconomical. Past studies preformed at UTRC have indicated that the thermally powered systems which utilize the endothermic process of vaporization of a working fluid could achieve good overall system performance levels. In addition, recent efforts by other organizations have indicated that adsorption air conditioning systems using various types of dessicants could have attractive features. Other processes (all of which are capable of producing significant cooling effects) such as the dissolution of solids in liquids, the formation of azeotropic and nonazeotropic liquid mixtures, fusion and sublimation, expansion of gases, and the thermoelectric and thermogalvanic effects have been studied. All were rejected because of unattractive performance levels or the initial costs of the resulting systems were shown to be substantially higher than thermally powered equipment already available or under development.

Thermally powered air conditioning systems which could utilize the vaporization of a working fluid as the cooling process are:

1. Engine-driven vapor compression systems using:
    - Otto cycle gas engine,
    - Brayton cycle engine,
    - Stirling cycle engine, and
    - Free piston engine.
2. Absorption systems using:
    - Ammonia-water,
    - Lithium bromide-water, and
    - Other absorbent-refrigerant combinations.
3. Double-loop systems with energy transfer via:
    - Ejectors,
    - Reciprocating expander compressor, and
    - Turbomachinery expander compressor.

### *Engine-Driven Vapor Compression System*

In a solar-powered engine-driven vapor compression system, solar energy would be converted into shaft work which is then used to drive a compressor similar to those used in electrical systems. The Otto- and Brayton-cycle, engine-driven concepts suffer from the requirement for relatively high maximum system temperatures for efficient operation and would require more complex collectors capable of providing temperatures of 1,000° F or more. Even if the solar collectors could be provided at reasonable cost, the engines themselves would be excessively high in first costs and require burdensome maintenance and overhaul procedures.

Work is presently in progress on a combination of the Stirling heat engine and Stirling refrigeration cycle as a means of using low-temperature heat input to provide air conditioning. The system requires high-pressure operation with helium or hydrogen as the working fluid and extensive regenerative heat transfer. However, small-scale cryogenic refrigerators have been built using this system.

Engines operating on the Rankine-cycle principle, which have received much attention in the last 10 years, will be discussed with the double loop systems.

*Absorption Systems*

An absorption air conditioning cycle offers a simple method of substituting a heat-actuated device with few or zero moving parts in place of a motor-driven vapor compressor. Absorption air conditioning systems are available in a wide range of sizes for residential and commercial applications and can operate with fossil fuel or low-temperature heat inputs. As a result of many years of operating experience, two basic absorbent-refrigerant combinations are presently used, $NH_3$-$H_2O$ and LiBr-$H_2O$. These combinations have been selected based on operating temperature, construction materials, and performance considerations.

In an idealized absorption system as shown in figure 3, the basic components are a generator, absorber, evaporator, and condenser. Additional components are usually included to improve the thermal COP (Coefficient of Performance, defined as the ratio of heat absorbed by the refrigerant in the evaporator to the heat content of the energy required to operate the system), and to reduce the quantity of absorbent vapor that would be carried into the condenser with the refrigerant vapor. These additions improve the system COP by about 20 to 30 percent for representative cycle operating conditions.

To further improve performance, still more components and cycle modifications are introduced into the absorption cycle. With sufficient heat transfer surface area in the added components, a thermal COP of about 0.70 can be achieved. Although numerous absorption systems using other absorbent-refrigerant combinations have been suggested over the years, low predicted performance levels, minimum advantage over the presently used combinations, or the lack of detailed thermodynamic data, have not encouraged further development. Although LiBr-$H_2O$ systems can operate efficiently at temperatures of 200° F in the generator, the materials of construction must be carefully selected. Lithium bromide-water systems have been restricted by the operating temperatures in the absorber and condenser and thus require water cooling to avoid crystallization of the lithium bromide. However, modification to the lithium bromide system is being investigated to permit air cooling (refs. 3,4).

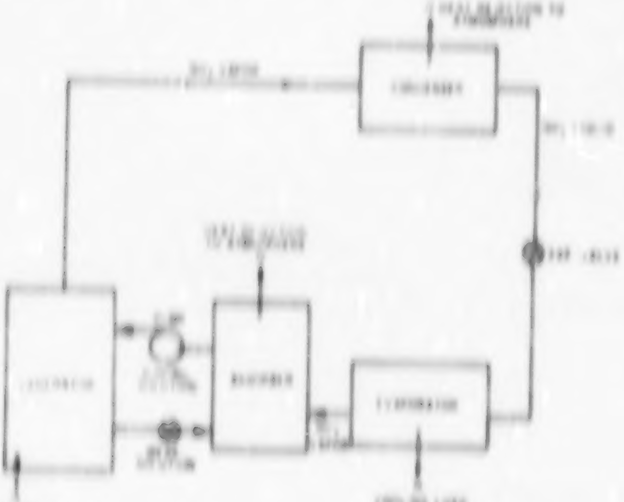

Figure 3. Ammonia water absorption system schematic.

*Double Loop Systems*

An important class of thermally powered air conditioning systems is based on the use of the so-called double-loop cycles. Although these cycles may differ in their details, they all utilize a self-contained Rankine-cycle power-conversion loop to provide the energy for a conventional vapor refrigeration loop. The energy from the power cycle can be transmitted to the refrigeration cycle by various means. One method is to use an ejector system in which the energy of a high-pressure, high-temperature fluid stream is transferred to the refrigerant vapor through a momentum transfer process. Another method would use a vapor expansion engine to drive a reciprocating compressor. Another method is to use a vapor-expansion turbine which drives a centrifugal compressor in the refrigeration loop.

All of these approaches have been pursued at one time or another with varying success. During the past year and a half, UTRC has been under contract to NSF/ERDA to demonstrate the operation of a Rankine-cycle heat pump system using the turbocompressor approach at system temperature levels consistent with present-day flat-plate collectors.

## TURBOCOMPRESSOR SYSTEM DESCRIPTION

The turbocompressor Rankine-cycle system concept for solar-powered heating and cooling is shown schematically in figure 4. It utilizes a single working fluid and common condenser for both the power and cooling loops. Hot fluid from the solar collector/storage system is used to vaporize a working fluid in the vapor generator of the power loop. The vapor is expanded through a turbine which produces mechanical power to direct-drive a compressor. The compressor pressurizes working fluid vapor leaving the evaporator to the level necessary for heat rejection to the atmosphere in the condenser. The exhaust of the turbine and compressor is mixed and enters the common condenser which may be air- or water-cooled.

A receiver is used at the exit of the condenser to permit smooth distribution of the working fluid to each loop. An expansion valve is used prior to the evaporator to lower the cooling fluid pressure and temperature to the desired level. A pump which may be driven off the same turbocompressor shaft circulates the working fluid in the power-conversion loop. A common nontoxic, inexpensive refrigerant such as R11 is preferable as the system working fluid. When heating is desired, the turbocompressor can be bypassed and the evaporator coil used as the heating element or the system can be operated in a heat pump mode. Any deficiencies in solar-generated heat would be made up by a supplemental burner.

The turbocompressor system has many advantages. For example, since the same working fluid is used in both the cooling and power loop, a common condenser can be utilized. Furthermore, elaborate seals are not required to separate the working fluid from each loop when mixing in the turbocompressor. Lubrication can be provided by the working fluid itself and thus the turbocompressor unit can be hermetically sealed. Single-stage compressor and turbine designs based on technology already demonstrated can result in a simple, yet efficient unit. Excess shaft power can also be generated, if desired, for auxiliary purposes and additional heat exchangers, i.e., a regenerator or precooler can be used to

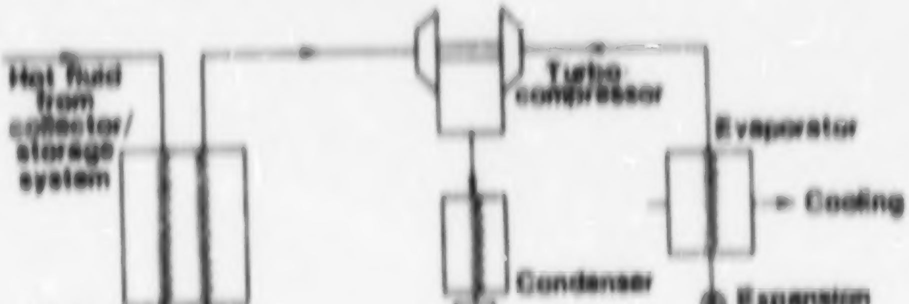

Figure 4. Turbocompressor system.

increase system performance, if cost efficient. These factors lead to high overall system efficiency even at relatively low operating collector and temperature levels.

## DEMONSTRATION TEST SYSTEM

The technical approach used for the feasibility demonstration of the Rankine-cycle turbocompressor concept is based upon the adaption of existing key components while providing the capability of the system to operate safely and efficiently at temperatures and conditions consistent with present-day flat-plate solar collectors.

The demonstration turbocompressor system has been assembled with two separate loops, one for power generation and the other for cooling (fig. 5). Although the same working fluid is used in both loops, separate condensers are used. This configuration permits more convenient operation and measurement of temperature and pressure conditions at the exhaust of the turbine and compressor elements, and therefore, provides a direct means for correlating calculated and experimental component performance. The two condensers are normally regulated to operate at the same temperature to simulate single condenser operation, although offset condenser operations are possible for specific tests.

Heat transfer at all of the system interfaces is via cold or hot water sources. This permits closer temperature control than would be feasible with air cooling. Heat input from a solar collector is simulated by a steam supply system which provides hot water to the power loop vapor generator over a range of inlet temperatures between 170° and 240° F. The condensers are capable of operating over a temperature range from about 80° to 130° F, thus simulating both water- and air-cooled operations.

The turbocompressor unit consists of a two-stage compressor mounted on one end of a shaft with a radial inflow turbine at the other end. The compressor selected for the turbocompressor demonstration unit is capable of producing in excess of 8 tons of cooling with R114 as the working fluid and was originally designed for use in an aircraft environmental control system. The rotating elements are less than 4.0 in. in diameter and operate at speeds of 20,000 to 35,000 rpm.

The shaft is supported by precision ball bearings that can accept both thrust and radial loads. Cooling and lubrication is provided by liquid refrigerant flow in the

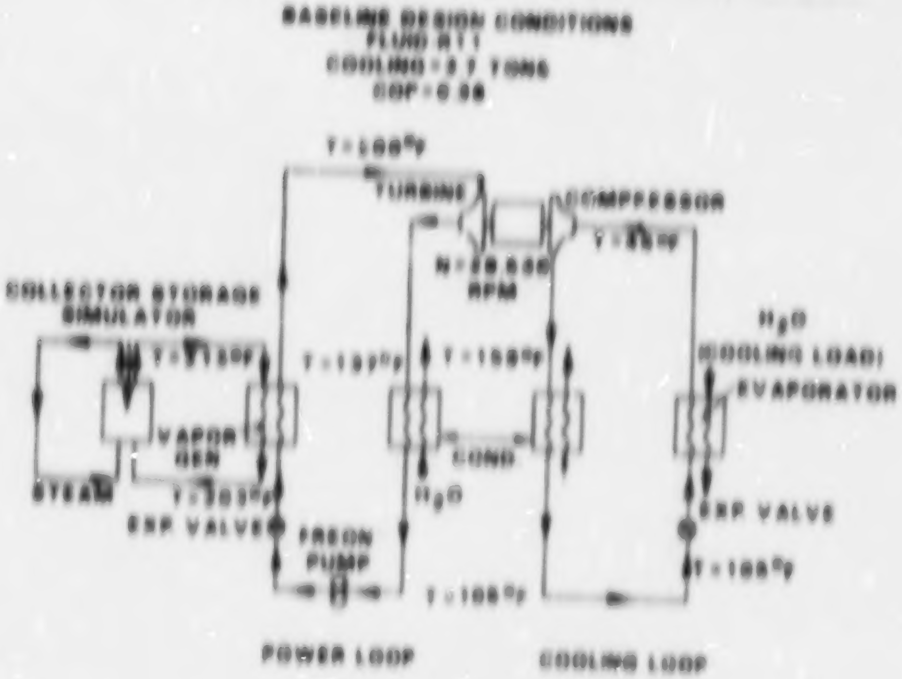

Figure 5. Demonstration system flow chart.

bearing cartridge. An expansion valve controls superheat in the bearing exit coolant stream to about 20° F, thus providing a relatively dry condition and minimum bearing losses.

The other major components in the system are heat exchangers. Two of these are evaporators and two are condensers. All are commercial units of the shell and tube type. The evaporators have water on the shell side which is baffled to improve the film coefficient.

The two condensers use water on the four-pass tube side. Both units are oversized for this application. As a result, it is possible to use the condenser as receivers since flooding the bottom tubes with liquid refrigerant does not prevent the unit from operating as required.

The demonstration system is shown in figure 6 as it appears in the UTRC laboratory. The overall dimensions of the system are approximately 8 ft long by 4 ft wide and 6 ft high. Although a more compact arrangement was possible, ample room was permitted for instrumentation and any desired modifications.

## TEST RESULTS

Over 60 performance test runs were obtained with the turbocompressor demonstration system and more than 60 hours of operation have been recorded. System operation has been achieved at turbine inlet temperatures ranging from approximately 180° F to above 215° F, condenser temperatures from 85° to 125° F, and evaporator temperatures from 30° to 70° F. About half of the tests have been at conditions close to the design point conditions of turbine inlet, condenser and evaporator temperatures of 200° F, 105° F, and 45° F respectively. The complete test results are summarized and presented in the reference 5 report.

The analyses indicate very close correlation between the test data and analytical predictions of system performance at condenser temperatures of 100° to 105° F. At other condenser temperatures, wider discrepancies between the test data and analytical predictions are noted with the test data generally higher than the analytical predictions.

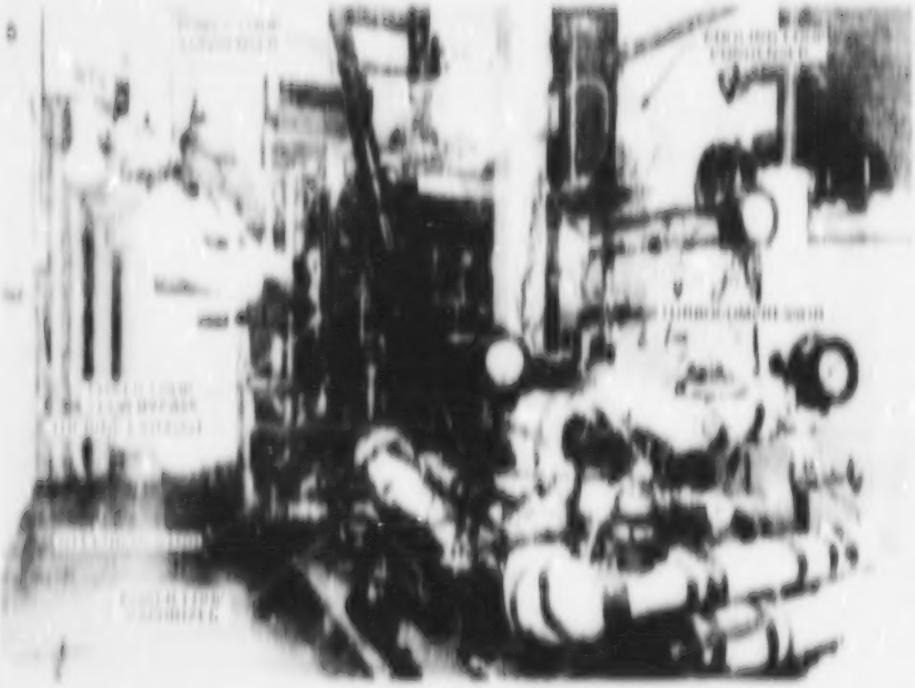

Figure 6. Demonstration turbocompressor system

Specific comparisons of the demonstration system test data and predicted values of performance and operating conditions have been made at selected test runs near the design point conditions. The cooling produced was generally somewhat higher than predicted (i.e., 4.08 tons versus 3.7 tons in one case), but the measured COP was slightly lower than predicted. Some of the reasons for the differences are described in the following paragraphs. Although the turbine inlet temperature during the test run was higher than the design baseline conditions of 200° F, the higher temperature is in the form of R11 superheat which does not significantly raise the COP of the turbocompressor system.

While turbomachinery efficiencies are as predicted or higher, system Coefficient of Performance with these conditions falls below that predicted mainly because the evaporator is operating at substantially less than 45° F and the flow to the compressor has an excessive amount of superheat. At the lower pressure associated with the reduced evaporator temperature, more compressor work is required to pump the gases to the condenser pressure and hence less flow can be circulated in the cooling loop with the available turbine power.

Other test data obtained at approximately the design point conditions also compare well with the predicted system performance. For example, data taken at a turbine inlet temperature of 200° F produced 4.33 tons of cooling at an evaporator temperature of 35° F with a COP of 0.34. The test data also illustrate the sensitivity of compressor performance to the desired compressor head conditions. The highest performance levels are achieved with temperature differences between the condenser and evaporator approaching 60° F or more, principally because the compressor was originally designed for relatively high pressure ratio operation.

Although much of the demonstration system testing was conducted at the nominal design conditions, operation at turbine inlet temperatures other than 200° F were obtained with condenser temperatures of approximately 105° F. A comparison of the Coefficient of Performance and Cooling Capacity data obtained from the demonstration system tests with that predicted from analyses is shown in figure 7 as a function of turbine inlet temperature. The predicted performance characteristics are shown in figure 7 by the solid line over a range of turbine inlet temperatures for a condenser temperature of 105° F and a compressor inlet temperature of 50° F. Since the compressor inlet temperature includes 5° F of superheat, the evaporator actually operates at a temperature of 45° F. The experimental data are indicated in figure 7 by the open circles and have been obtained over a range of condenser and evaporator temperatures close to those used for the calculated performance curves. The data shown indicate that the cooling produced ranged from 2.15 tons to 4.33 tons with a measured COP ranging from 0.20 to 0.34. Some differences between test and predicted performance are noted at turbine inlet temperatures of 200° F and above. A portion of this difference can be attributed to the fact that during the tests the system operating conditions did not duplicate all the conditions used to analytically predict performance.

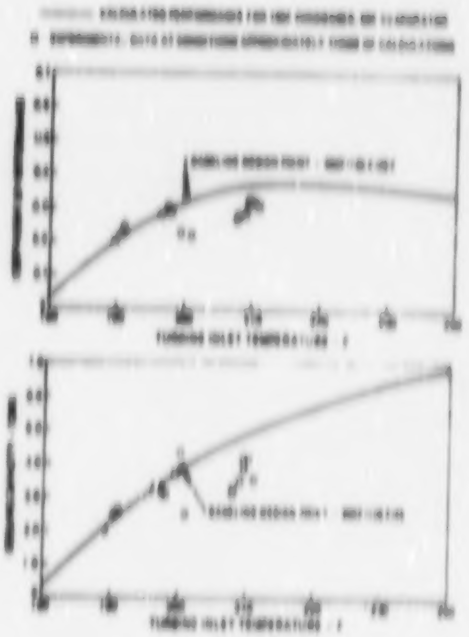

Figure 7. Demonstration system performance characteristics.

The results obtained when operating the demonstration system at condenser temperatures slightly lower than the baseline condition of 105° F are encouraging. Data were obtained for turbine inlet temperatures from 190° to 198° F, although evaporator temperatures were generally higher than desired. During some of these tests, a COP of 0.40 was obtained with a turbine inlet temperature of 190° F. The flow utilized for cooling the turbocompressor bearings was reduced during some selected runs and is believed responsible for the relatively good performance.

Test results were also obtained when operating the demonstration system at condenser temperatures of approximately 90° F. While only a limited number of test runs were completed at this lower condensing temperature, experimental performance met or exceeded performance predictions and a COP approaching 0.40 was obtained. Substantial cooling was produced with anticipated levels of Coefficient of Performance at turbine inlet temperatures as low as 163.5° F together with evaporator temperatures of 45° F or below.

A review of all the test data over the range of turbine inlet and condenser temperature conditions investigated indicate that only approximately a 70° to 80° F temperature difference between the vapor generator and condenser is required for the turbocompressor system to operate. With selected improvements to the system even lower temperature differences should be feasible for efficient operation.

## PERFORMANCE POTENTIAL

Although the turbocompressor demonstration system has exhibited impressive performance, especially at turbine inlet temperatures between 180° and 210° F, substantial improvement is possible. One means of improving performance is by incorporating specifically designed and matched turbomachinery elements rather than using modifications of existing equipment. While the present turbomachinery has generally met or exceeded the performance levels predicted analytically, much higher performance levels are achievable, especially for industrial turbocompressor systems designed to provide from 25 to hundreds of tons of cooling and using larger compressor and turbine wheels than those used in the present program. Even systems designed for the residential and small commercial markets; i.e., 3 to 20 tons, can utilize turbomachinery which have component efficiencies higher than those achieved in the present system. An artist's concept of such an advanced turbocompressor is shown in figure 8. Such a unit, approximately 6 in. in diameter and less than 9 in. long would be suitable for use in a 3- to 5-ton domestic heat pump system. With such machinery, the system COP can be increased by 35 percent above the present levels and system component sizes (including the solar collector and storage systems) reduced accordingly. Turbocompressor systems sized for the industrial market would be more efficient because of the larger physical dimensions of the components thus reducing some of the losses inherent in small components. These larger components should be capable of achieving efficiencies approaching 85 percent or more. As a result, the turbocompressor product efficiency levels (i.e., compressor × turbine efficiency) achieved with the present system (50 percent) can be increased with further development to 64 percent for residential systems and to 72 percent for industrial systems. Coefficient of Performance levels of the turbocompressor system would correspondingly be increased to levels approaching 1.0 even when operating at 200° F turbine inlet temperatures. The performance levels achievable with the turbocompressor system as a function of turbomachinery product efficiency and turbine inlet temperature are shown in figure 9.

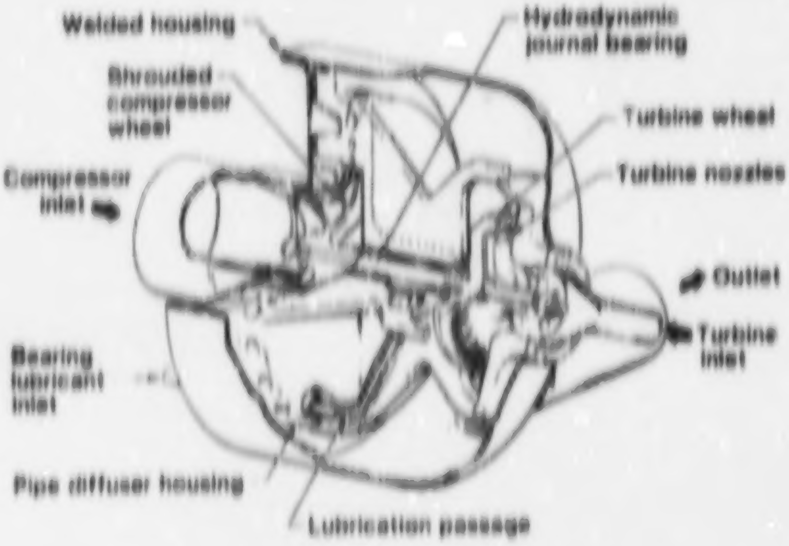

Figure 8. Turbocompressor unit design.

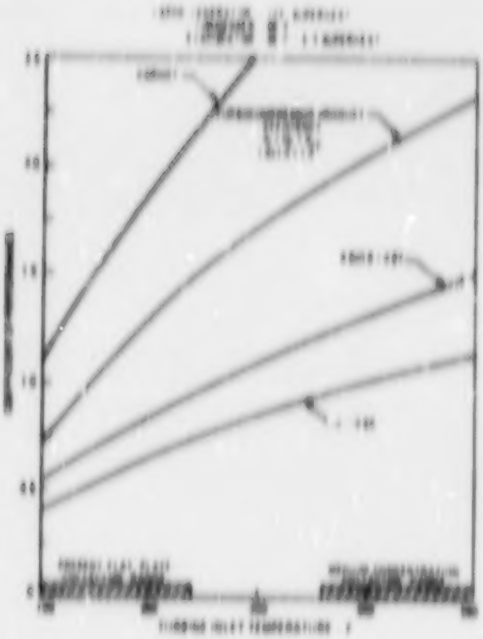

Figure 9. Turbocompressor system performance potential fluid R11.

The results shown in figure 9 for a condenser temperature of 90° F also indicate the substantial potential for higher system performance when operating at turbine inlet temperatures above 200° F. For example, a COP greater than 1.1 can be achieved at a turbine inlet temperature of 240° F with a turbocompressor product efficiency of 64 percent. Thus in the future, marked improvements in turbocompressor system performance could be achieved with the use of medium-concentrating collectors and specifically developed turbomachinery.

## CONCLUSIONS

1. A turbocompressor Rankine-cycle system has been designed, built, and operated efficiently and reliably at peak system temperatures consistent with present-day flat-plate solar collectors.
2. Substantial improvements in turbocompressor system performance and therefore size and cost are feasible with added component and overall system development. The full-scale implementation of solar heating and cooling with a turbocompressor system could be brought to commercial development within 3 to 5 years.
3. With continued intensive development, building heating and cooling systems, using solar energy, could make a contribution to significant energy conservation in the United States.

## ACKNOWLEDGMENT

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# EVALUATION OF ENGINE-DRIVEN HEAT PUMP SYSTEMS OF SMALL CAPACITIES[*]

Jaroslav Wurm and Gopal P. K. Panikkar[†]

## Abstract

*One generally recognized and immediately available method for conserving the energy used for space conditioning is the heat pump. Studies have shown that among heat pumps, those with certain component characteristics could greatly increase the energy savings usually resulting with heat pumps. One such preferred system recognizes the special operating requirements of a small air-to-air heat pump by utilizing an onsite gas-operated prime mover as the driver.*

*This paper discusses the results of performance evaluations of various systems of this type and analyzes the consequences of operating residential Rankine and Brayton heat pumps driven by Otto, Stirling, Brayton, and Rankine power subsystems. Since some of the candidates have already reached the level of hardware testing, their characteristics are applied to machines with two types of capacity modulation where the onsite recovery of the engine's rejected heat is used in the heating mode.*

*The results show that when compared with an electrically driven, residential heat pump applied to a typical house heat load, the air-to-air heat pump driven by an onsite gas-operated prime mover exhibits:*

*1. Superior performance (in terms of seasonal COP),*

*2. A possibility of meeting comfort conditions over a wider range of ambient temperatures, especially for the heating mode.*

## INTRODUCTION

For several years the Institute of Gas Technology (IGT) has been studying various concepts of residential air-to-air heat pumps to assess their energy-saving potential and their practicability. Our approach has been quite broad. The scope of the studies even included cycles, components, and systems that had never before been considered for conventional[¶] heat pump service. Methodically, we have progressed from studying idealized systems (ref. 1) to evaluating practical systems at design (ref. 2) and off-design operating conditions. Some of our objectives called for identifying potential problem areas and design and operating improvements for both the existing and new components and systems. Finally, we identified concepts with sufficient promise to warrant further development. This paper discusses the part of our work specifically related to achieving these objectives.

## BACKGROUND

The new generation of conventional, residential, air-to-air heat pumps is becoming an important factor in our energy conservation efforts. The reliability of commercially available units has improved significantly, and the manufacturers have launched programs for dealers to improve installation and servicing practices. The performance and quality of heat pumps has been improving based on continuing component and system design research that had been initiated on a larger scale in the 1950's.

However, even the very best conventional, residential heat pump has its preferential range of operating conditions, and so realizing the full energy-saving potential thus depends on the designer's ability to widen the range of conditions over which a heat pump could be advantageously used and/or on defining the application limits. Generally, these limits (for conventional residential Rankine heat pumps) are inherently related to the direct proportionality between the ambient (source) temperature and the heat pump's capacity. In the heating mode, this actually translates into two problems: The heating capacity decreases as the temperature of the ambient air decreases, and the heat delivered is at lower and lower temperatures. Less efficient supplemental heating is commonly used to correct these inadequacies. In the case where this is done by resistance heating, the seasonal effectiveness of the system is penalized to such an extent that in northern climates, the benefits of the heat-pump effect vanish, and the seasonal effectiveness approaches that of a conventional furnace (ref. 3).

The fact that, for marketing reasons, the present residential heat pumps are being designed as both heaters and air conditioners,[§] with the design point within the

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[¶] By "conventional," we mean a heat pump supplying heat or cold to condition the living areas.

[§] For example, in the United States only recently have "heating only" heat pumps been introduced on the market.

cooling-mode range of conditions, certainly does not moderate the detrimental effect of variable operating conditions on the year-round effectiveness. Yet, system designs that can achieve the maximum of the heat-pump' energy-saving potential have been conceived. Lately, some have reached the market place; others are being evaluated or have reached an experimental stage (ref. 4).

The objective of the studies at IGT was to assess the feasibility of a special group of residential comfort systems: engine-driven heat pumps, a group that has high potential for improved energy savings. We believe that for certain residential heating and cooling applications, engine-driven, air-to-air heat pumps will provide total year-round energy savings higher than that attainable with conventional heat pumps. This results from:

1. The on-site recovery and utilization of the engine's rejected heat, and

2. Operating the heat pump and its components at conditions where high efficiencies are achievable.

The validity and feasibility of these two factors have also been discussed in detail in reference 2. The systems and components selected for our investigation, the method of evaluating the heat-pump design-point and off-design performance, and the results of the evaluation are presented below.

## SELECTION OF SYSTEMS, COMPONENTS, AND OPERATING MODES

An evaluation of a heat-pump system on a seasonal and year-round basis requires consideration of many individual steps. For every system, the sequence of these steps (including an internal looping and iterative approach not indicated here) includes:

1. Selecting and sizing components,
2. Generating and/or evaluating component characteristics,
3. Component matching and generating heat-pump system characteristics,
4. Matching the system and load characteristics (heat pump/house),
5. Selecting the operating modes,
6. Applying the heat pump/house system in selected climates by using statistical weather data.

To better understand the evaluating procedure, some of these important steps are described below.

### *System Selection*

For the design-point and off-design performance evaluation, we have selected systems on the basis of evaluations of idealized heat-pump candidates, the suitability of the components, and the availability of real component characteristics.

Analytically, we have discarded the Stirling refrigerator as not showing potential for conventional heat-pump applications (ref. 8). It shows superior performance only for greater differences between the sink and source temperatures than that encountered in conventional heat-pump service. In spite of its relatively poor cooling performance, we have assumed that the Brayton refrigerator is a reasonably good candidate because of its stable and relatively high heating performance. The Rankine refrigeration subsystem, and specifically its mechanical configuration,[*] is the only one for which the applicability has been verified, and systems using it have been marketed. Thus, two candidates remained for consideration: the Brayton and the Rankine refrigeration subsystems.

Suitable prime-mover subsystems for driving the refrigerators were selected purely on the basis of availability of desired component characteristics.[†] Although diesel engines were not represented, the applied drivers still include all of the important groups of prime-mover subsystems. One hundred percent efficient, constant and variable-speed electric motors were used, primarily for reference cases.

For evaluation purposes, we have formally "designed" several systems using suitable combinations of prime-mover and refrigerator subsystems. The potential and evaluated systems are depicted in table 1.

### *Component Selection*

All of the components used in our evaluation were represented either by measured or generated and experimentally verified performance characteristics. None of them was, however, designed for heat-pump service; we assumed that the required design changes would be possible for the preferred configurations. The components used and their characterization are as follows:

1. An automotive air-conditioning compressor—open, single cylinder, 98.3 cm$^3$ (6 in.$^3$) displacement, 300 to 4,000 rpm, driven by:

a. Hypothetical engine or motor with constant, source energy efficiency of 30 percent,

b. Otto, 4-stroke, 1-cylinder, air-cooled, stationary engine with an output of 4 to 14 hp and 1,800 to 3,600 rpm,

c. Stirling, double-acting, 4-cylinder engine with swashplate, 16 cm$^3$ (1 in.$^3$) displacement of helium, pressure and rpm modulated,

d. Stirling, double-acting, 4-cylinder engine in V arrangement with pressurized crankcase.

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[*] Absorption systems were studied separately (ref. 8).

[†] At the time of the investigation, not all of the necessary characteristics of components desirable for evaluation were available to us.

Table 1. Component matrix of engine-driven, residential heat pumps indicating potential and evaluated systems

PRIME MOVER SUBSYSTEM

| CYCLE | | HYPOTHETICAL ENGINE OR MOTOR | | OTTO | | | DIESEL | BRAYTON Open, Regenerative | | STIRLING Heat | | | | RANKINE Steam | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | MACHINERY | CONSTANT SPEED | VARIABLE SPEED | PISTON | | ROTARY | PISTON | TURBINE | | SINGLE ACTING | DOUBLE ACTING | | FREE PISTON* | PISTON | ROTARY* | TURBINE |
| | DESIGN | | | MOD 1 | MOD 2 | | | MOD 1 | MOD 2 | | MOD 1 | MOD 2 | | | | |
| REFRIGERATING SUBSYSTEM: RANKINE R-12 | PISTON MOD 1 | ■ | ■ | ▨ | ░ | | | | | | ░ | ▨ | | | | |
| | PISTON MOD 2 | | | ░ | | | | | | | | | | ░ | | |
| | ROTARY | | | | | | | | | | | | | | | |
| | TURBO | | | | | | | | ▨ | | | | | | | |
| REFRIGERATING SUBSYSTEM: BRAYTON Vapor, Open, Air, Regenerative | ROTARY* | | | | | | | | | | | | | | | |
| | TURBO | | | | | | | ░ | | | | | | | | |

□ NOT EVALUATED

░ DESIGN-POINT EVALUATED

▨ OFF-DESIGN EVALUATED

* NO CHARACTERISTICS AVAILABLE

2. An automotive air-conditioning compressor redesigned for a refrigeration application, open, single-cylinder, 139 cm³ (8.5 in.³) displacement, 600 to 2,000 rpm, driven by:

a. Otto, 4-stroke, 1-cylinder, air-cooled, stationary engine with an output of 1.3 to 10 hp and 1,800 to 3,600 rpm.

b. Rankine semiuniflow, 4-cylinder, 262 cm³ (16 in.³) displacement, steam expander with an output of 1 to 10.7 hp and 1,100 to 2,800 rpm, 80 percent efficient regenerative boiler (generating 1.72 kPa (250 psia) and 325° C (615° F) maximum steam conditions) with atmospheric or vacuum condensation.

3. Turbocompressor (Rankine, R-12) of an experimental design, driven by an experimental, vacuum, regenerative gas turbine.

4. Brayton experimental refrigerator consisting of a radial turbocompressor (slightly backward vanes) with a slightly curved diffuser, a nominal design specific speed of 25,000 rpm, pressure ratio 1.9, and a radial inflow expander with a nominal pressure ratio of 1.73. The refrigerator was driven by an experimental gas turbine consisting of a radial turbocompressor (straight), curved diffuser, a radial inflow expander, and an atmospheric combustor with recuperator.

### *Operating Modes*

One of the advantages of an engine-driven heat pump is the flexibility in designing the controls that establish the relationship between the instantaneous capacity of the machine and the heating/cooling load on the house. We call this relationship the "operating mode." This flexibility gives the designer the possibility of optimizing the energy consumption of a heat pump by *modulating* its capacity relative to the load. The detailed explanation as to why the capacity modulation could be beneficial to the heat-pump performance can be found in reference 2. However, at this point we will reemphasize two important aspects of capacity modulation:

1. Several ways of achieving desirable changes in the capacity of a heat pump's refrigeration subsystem—types of modulation—exist. For systems with piston compressors, these include speed variation, suction throttling, clearance volume control, lifting of the suction valve, and discharge bypass. Some of these ways can be used with systems having turbocompressors for which an inlet guide-vane control should be added.

2. Several ways of *applying* the preferred type of modulation also exist. For example, a control mechanism can be designed in such a way that the required load on the house is always matched by the capacity of the heat pump.[2] Although this concept of applying the modulation results in improved effectiveness (coefficient of performance—COP), it does not yield the ultimate benefits. Equally, applying modulation to follow solely the operating points of highest system efficiency (with respect to the variable ambient conditions) would not yield the best economy. This is because of the relationship between the combined component efficiency and the changing temperature differences on heat exchangers, each influences the COP's instantaneous values differently and, at certain ambient conditions, even in opposite ways. The resulting influence also varies from system to system.

In our evaluation we used two types of capacity modulation: (1) variation of speed for piston compressors, and (2) speed variation and inlet guide-vanes for turbocompressors. Also we have assumed only the simplest form of applying modulation, that of matching the capacity of the system with the load to the balance points. For certain conditions (for turbosystems and around an ambient temperature of 18° C (65° F)) an on-off control was also used.

Although simplistic, our approach served the purpose well. It identified the existence of improved energy savings and quantified its approximate level, even for systems with simplified versions of capacity modulation.

## EVALUATION OF SELECTED SYSTEMS AT DESIGN CONDITIONS

Early in the program we set out to prove that it might be beneficial to the system COP to operate both the prime mover and the refrigerator subsystems so that the actual operating points would follow conditions corresponding to high component efficiencies, at least for periods representing a high percentage of cumulative energy inputs. Other COP benefits attributed to capacity modulation and derived as a consequence of the decreased temperature difference on heat exchangers (due to lower load at milder conditions) had already been proven (refs. 7-9). Therefore, we decided to study the former energy-saving potential separately and specifically for our selected systems. For this purpose, the design-point evaluation is very well suited.

### *General Assumptions*

The relative performance of various comfort systems may be evaluated by using values of the COP for each system. For our purposes, we selected as the most important characteristic, the COP versus the ambient air, dry-bulb temperature, assuming a constant indoor-comfort level. We stress again that in this particular case (and unlike the case of the off-design evaluation), all of the COP values so calculated relate, for each point, to variable "design conditions," meaning that the sizes of the heat exchangers were specified only by constant temperature profiles.

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[2] The practicality of such an arrangement, the compatibility with the house distribution system and auxiliary power consumption, and the operating range of components are disregarded here.

To perform the graphical analysis of the performance behavior of our modulated systems, a load characteristic had to be defined. The system and load characteristic would then be superimposed and operating points defined according to the desired control system. We have done this for our design performance studies, as indicated in figures 1 and 2.

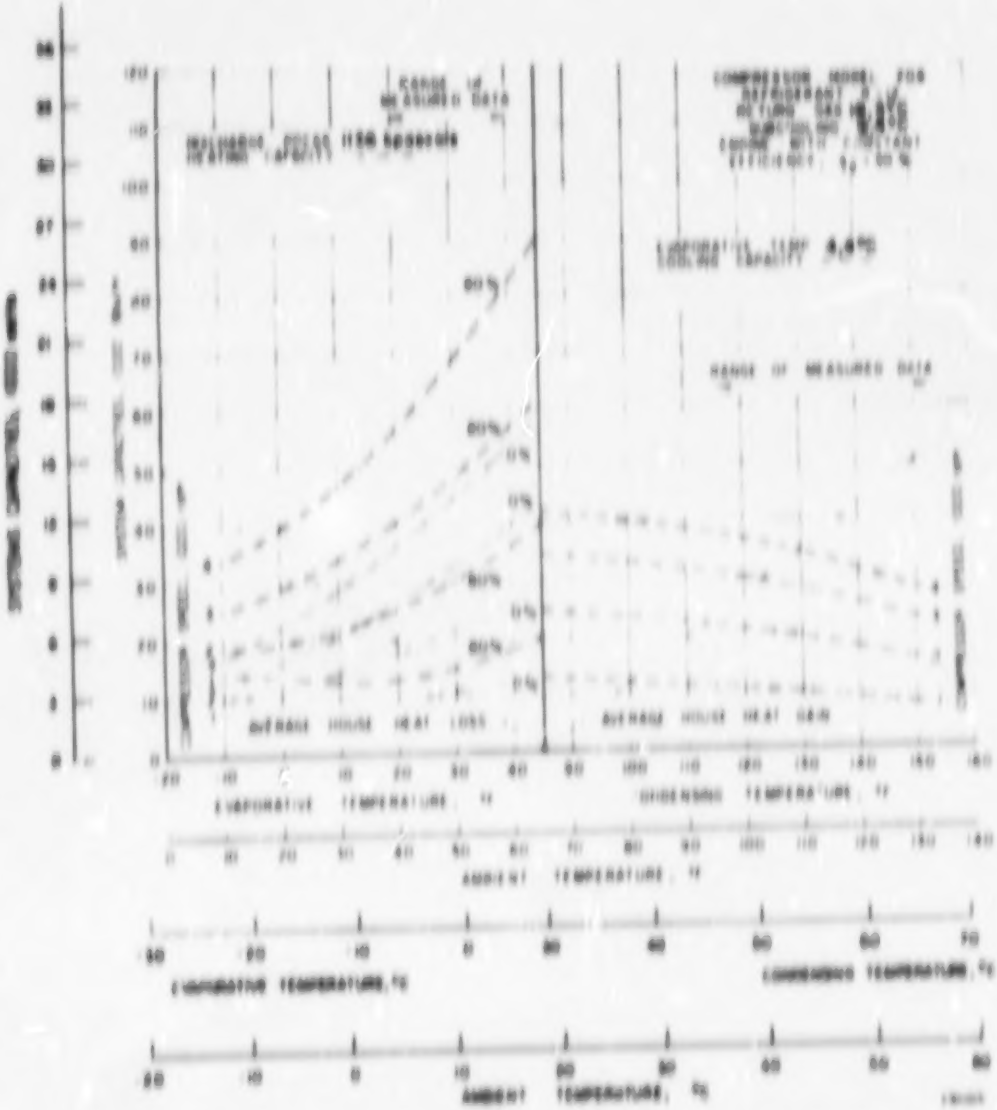

Figure 1. Heating and cooling capacity of a Rankine piston compressor heat pump driven by a constant efficiency prime mover (heating capacity lines correspond to 0 percent and 80 percent recovery of the engine's rejected heat).

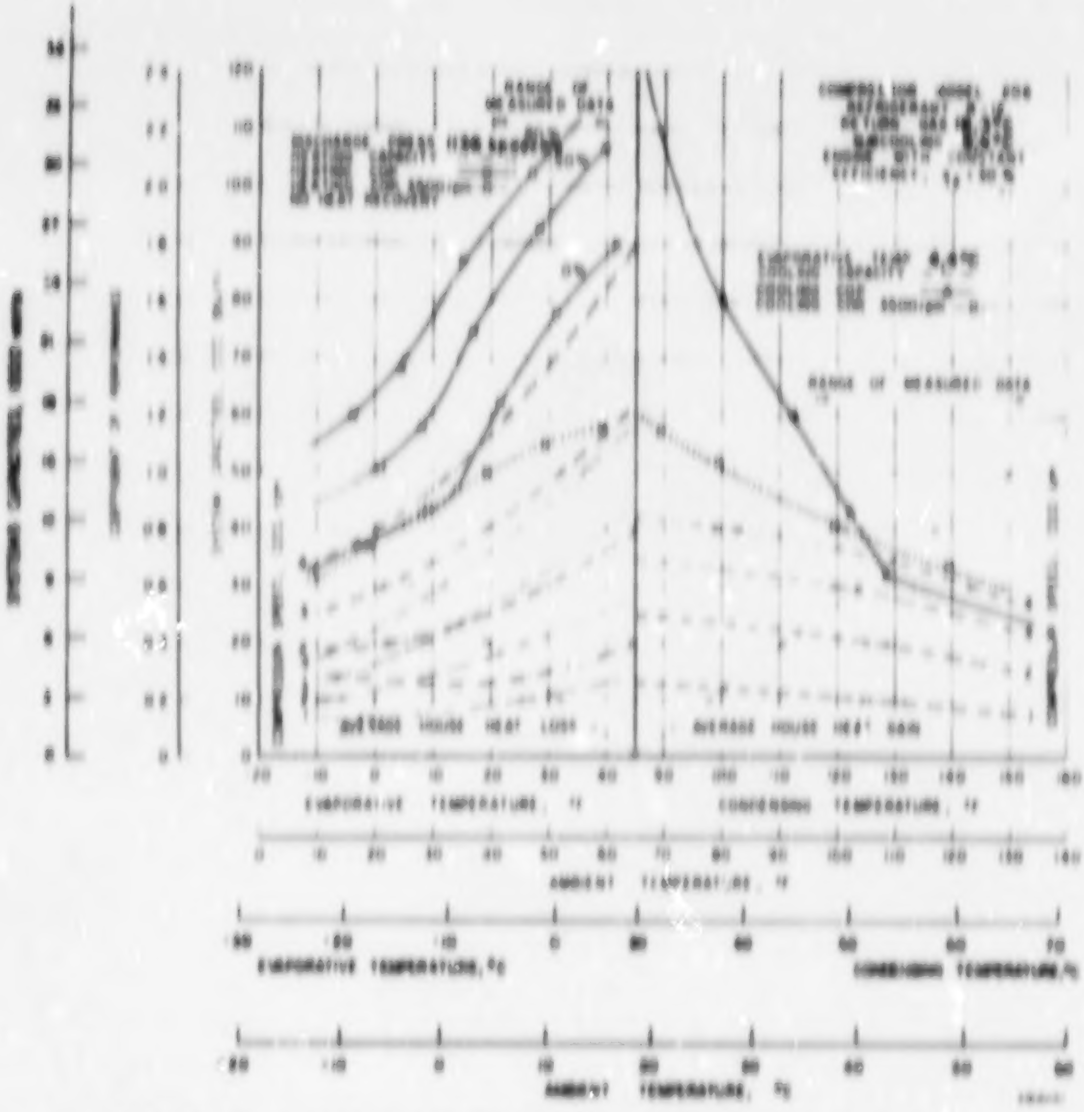

Figure 2. Heating and cooling performance of a Rankine piston compressor heat pump driven by a constant-efficiency prime mover (heating COP lines correspond to 0 percent, 50 percent, and 80 percent recovery of the engine's rejected heat).

*Results*

The important results of our design-point evaluation are presented in figure 3. There, for reference purposes, a band of COP's is accentuated. Its lower limit represents typical values of COP's for a residential, electrically driven heat pump, as given by a manufacturer. These values include the average efficiency of electric power generation and transmission (29 percent); for cooling they represent the total capacity. Supplemental heat, auxiliary power, and motor efficiency are excluded. The upper limit of our reference band is a COP curve calculated for a system comparable to an electrically driven

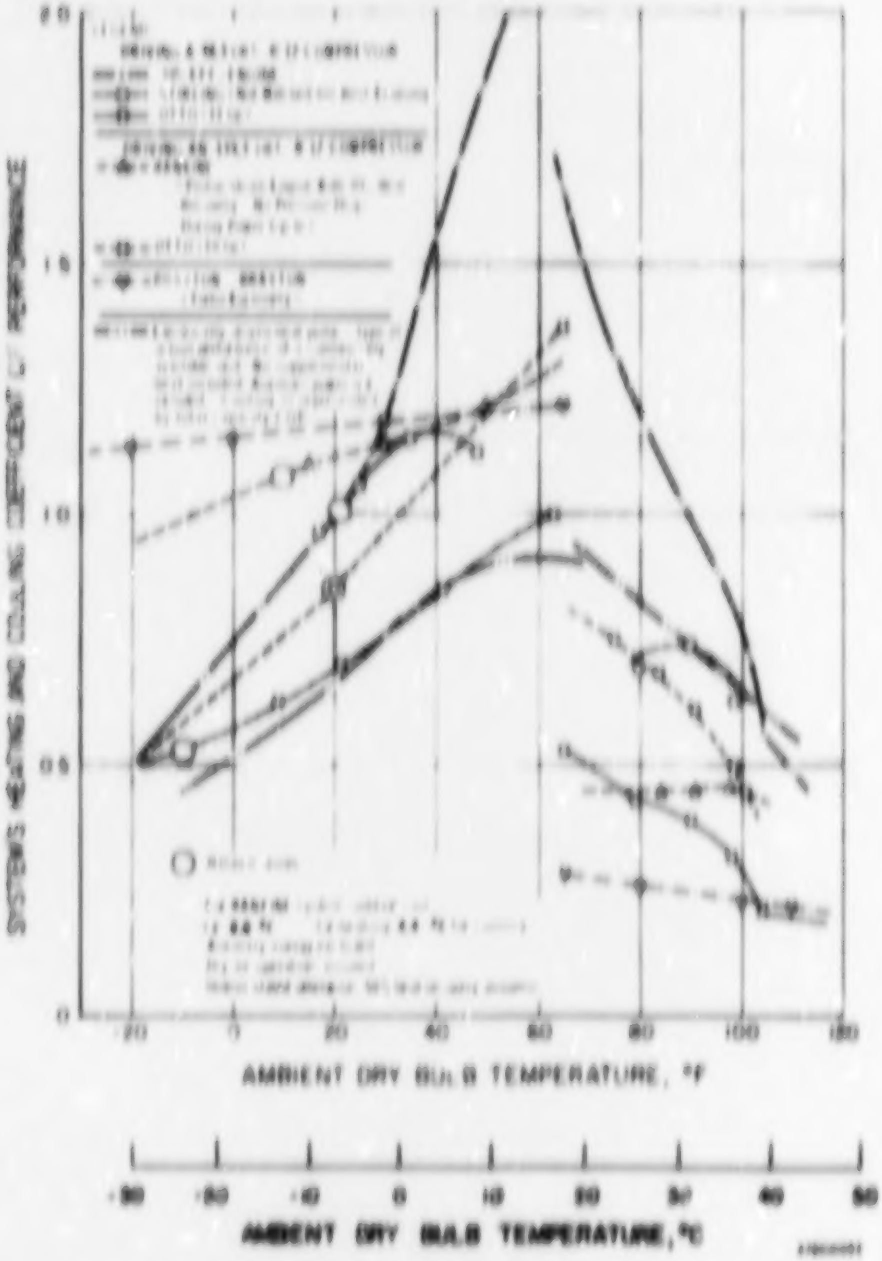

Figure 3. Coefficient of performance of various air-to-air heat pumps (for engine-driven systems, the values do not include the benefits of decreasing temperature differences on the heat exchangers).

heat pump. In this case, however, the compressor capacity always equals the house load. This is accomplished by varying the compressor speed within the practical range of 1,000 to 4,000 rpm. The driving hypothetical prime mover has a constant efficiency of 30 percent, and, for heating, 50 percent of its rejected heat is recovered. The curve, therefore, represents the potential performance of a piston compressor with a selected type and application of capacity modulation. However, this is still without the benefits resulting from decreasing temperature differences.

Superimposed, one can find the performance curves of several practical systems, which were calculated by using available characteristics of refrigerators and prime movers.

### *Conclusions*

Because of its limited value, the design point evaluation was not carried out all the way to the assessment of the year-round performance. However, it was sufficient to comparatively demonstrate the increased energy-saving potential of various modulated systems with or without recovery of the engine's rejected heat. Also, the results are sufficiently significant to suggest three basic conclusions:

1. The positive effect of capacity modulation on the COP of the analyzed systems, derived from operating the refrigerating subsystems at high efficiencies, is significant, but it can be destroyed by improper matching with prime movers. Because of the other positive effect of modulation—namely, the effect of variable temperature gradient on heat exchangers—the systems with capacity modulation will always consume less energy as compared with unmodulated systems, when proper attention is given to selecting and matching a driver. Therefore capacity modulation should be regarded as highly desirable for increasing the energy-saving potential of a heat pump.

2. Substantial improvements in the heating COP of a residential heat pump can be achieved by using an engine to drive the refrigeration subsystem. In practice, at least 50 percent of the engine's rejected heat can be used directly to boost the heating COP, heating capacity, and temperature of the delivered air.

3. Capacity-modulated systems, specifically those driven by an onsite prime mover with rejected heat recovery, show a capability of operating a wider range of ambient temperatures than unmodulated systems.

We also concluded that the results justified proceeding with the off-design and year-round performance studies. Some results of this evaluation are given next.

## OFF-DESIGN AND YEAR-ROUND PERFORMANCE EVALUATION

Ultimately, the practical rating of various heat pumps must be based on the comparative evaluation of their seasonal and year-round performances as related to specific climates. Other than an experimental determination, this would be the only way to establish such important data as, for example, the cumulative energy consumption. Another reason for this evaluation is that different systems respond differently to the given climatic conditions. For example, if a heat pump were designed for heating only, a Brayton-Brayton system could yield superior results (fig. 8); on the other hand, for conditions where both cooling and heating loads exist, the Rankine refrigeration system, both in piston or turbocompressor configuration,[7] driven by a Stirling engine or gas turbine, gave the most promising results. We specifically evaluated these latter systems, and in the following pages, we give some of the results for a selected application of a Stirling-Rankine heat pump.

### *General Assumptions*

An important part of the year-round performance analysis is generating the off-design characteristics of a system. Again, we selected the capacity and power consumption (and the resulting COP) as functions of the ambient dry-bulb temperature, for constant indoor temperature, to be the most important characteristics. In this case, however, the sizing of the heat exchangers came in consideration, and it required specification of the design point. This was done in such a way that two conditions were satisfied:

1. The evaporator temperature during cooling was kept above 0° C to avoid icing, and

2. For all the operating conditions, the pressure ratio was limited to less than 5.

The load characteristics, that is the cooling and heating loads on the house, were chosen primarily as they were for the design-point studies. They correspond to a load on an average-size, single-family, well-insulated residence. For the cooling season, one-third of the load was added to compensate for the latent heat of moisture condensation.

The weather data for the case presented were taken from reference 10.

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[7] The turbocompressor system analysis had not been completed before submission of this paper.

**Results**

To show the significance of the off-design performance analysis and the significant differences in COP for the design-point and off-design evaluations, we calculated the two characteristics for a Rankine piston, compressor heat pump driven by a hypothetical prime mover with constant efficiency of 30 percent. The comparative performance results for this simple system are presented in figure 4.

The significance of these results is related to our definition of the design-point performance. As we have defined it, the difference between the two approaches was that the design-point evaluation specified the heat exchangers only by a constant temperature profile (leaving their size variable), while the off-design performance corresponded to a totally designed system. Therefore, in figure 4, the less steep COP curves represent only the benefits of operating the compressor at higher efficiencies when modulating by speed, and the steeper COP lines reflect the additional benefits of decreased load on the heat exchangers.

The rest of the results gives an example of the comparative performance evaluation of a speed-modulated, Stirling engine-driven, Rankine piston compressor, heat pump with engine-heat recovery. This system was one of those that we selected as having high potential for becoming a practical, reliable, and efficient residential heat pump. For this evaluation it was "designed" to serve a typical single-family residence in the Chicago area, and its off-design performance is given in figure 5. In comparison with other selected systems, its COP characteristics as a function of the ambient air, dry-bulb temperature are given in figure 6, and its comparative energy-saving potential is given in table 2. Also, in table 3 the total annual emissions for the evaluated systems are compared.

## CONCLUSIONS

A study such as ours must be supplemented by an evaluation of other factors related to operating and manufacturing a system if it is to be used as a guideline in selecting a system for preferential development. These additional aspects would include:

1. Comparison between the performance of residential and district-type heat pumps,
2. Assessment of auxiliary power consumption,
3. Evaluation of other types of modulation and other (optimal) ways of applying modulation,
4. Assessment of control complexity,
5. Evaluation of interaction between the modulated heat pumps and the distribution system.

The influence of some of these aspects on the system performance might not be secondary. However, our results are important because they confirmed our conclusions, made previously, of design analysis, and they define and quantify incentives for additional system design and experimental research.

The components used in our evaluation were not specifically designed for heat-pump service, and we have necessarily assumed that the required design changes were practical. We were able to assess the feasibility of these changes only theoretically, but we are confident that some of the systems (such as Stirling-Rankine piston system and Brayton-Rankine turbocompressor system) could be developed into marketable hardware.

Finally, as a result of our design and off-design assessment of various residential heat pump systems, we have concluded that practical engine-driven heat-pump systems can be developed that would indeed show performance improvement relative to existing systems. One such candidate identified as extremely promising is the Stirling-Rankine piston heat pump.

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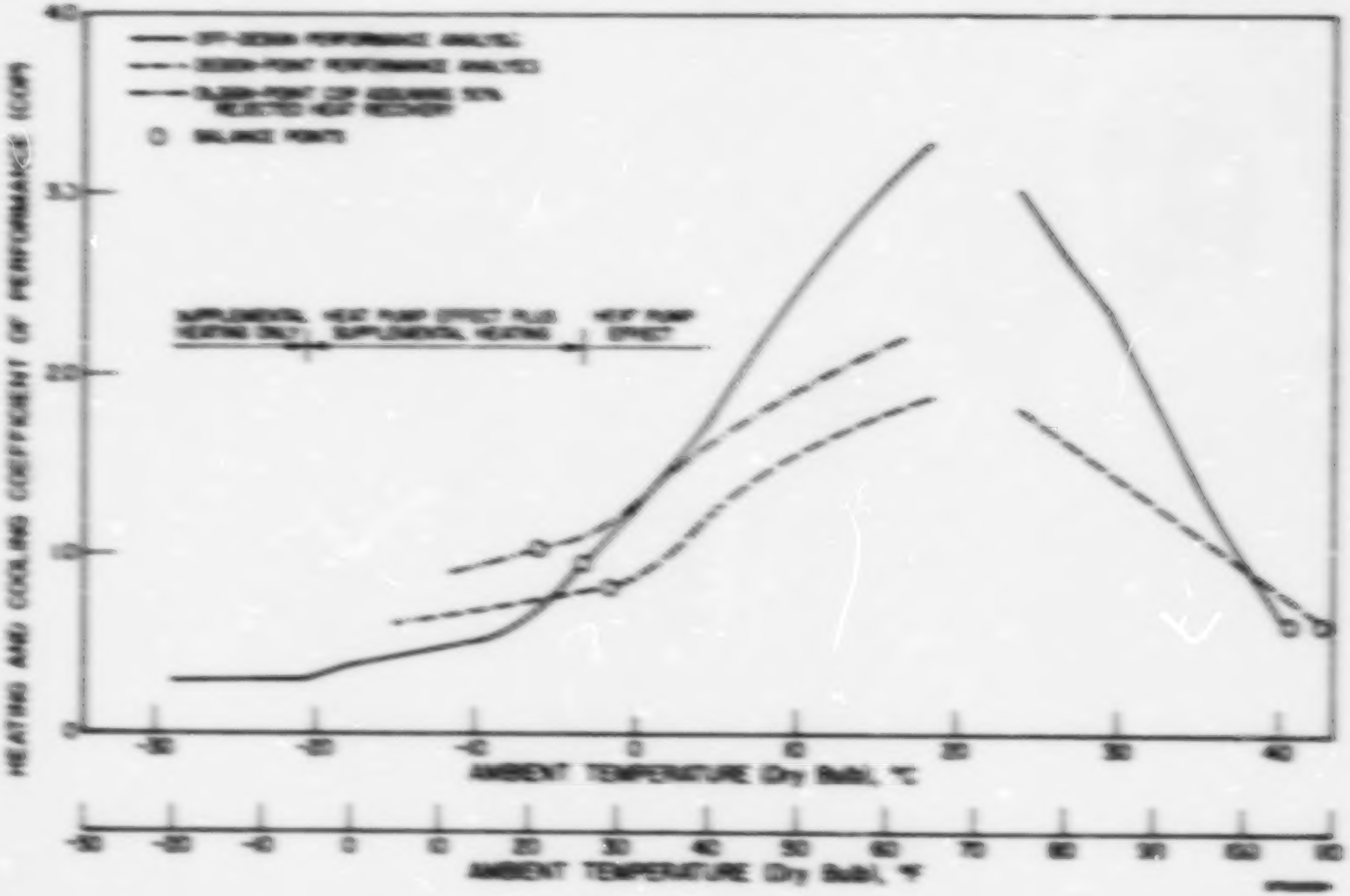
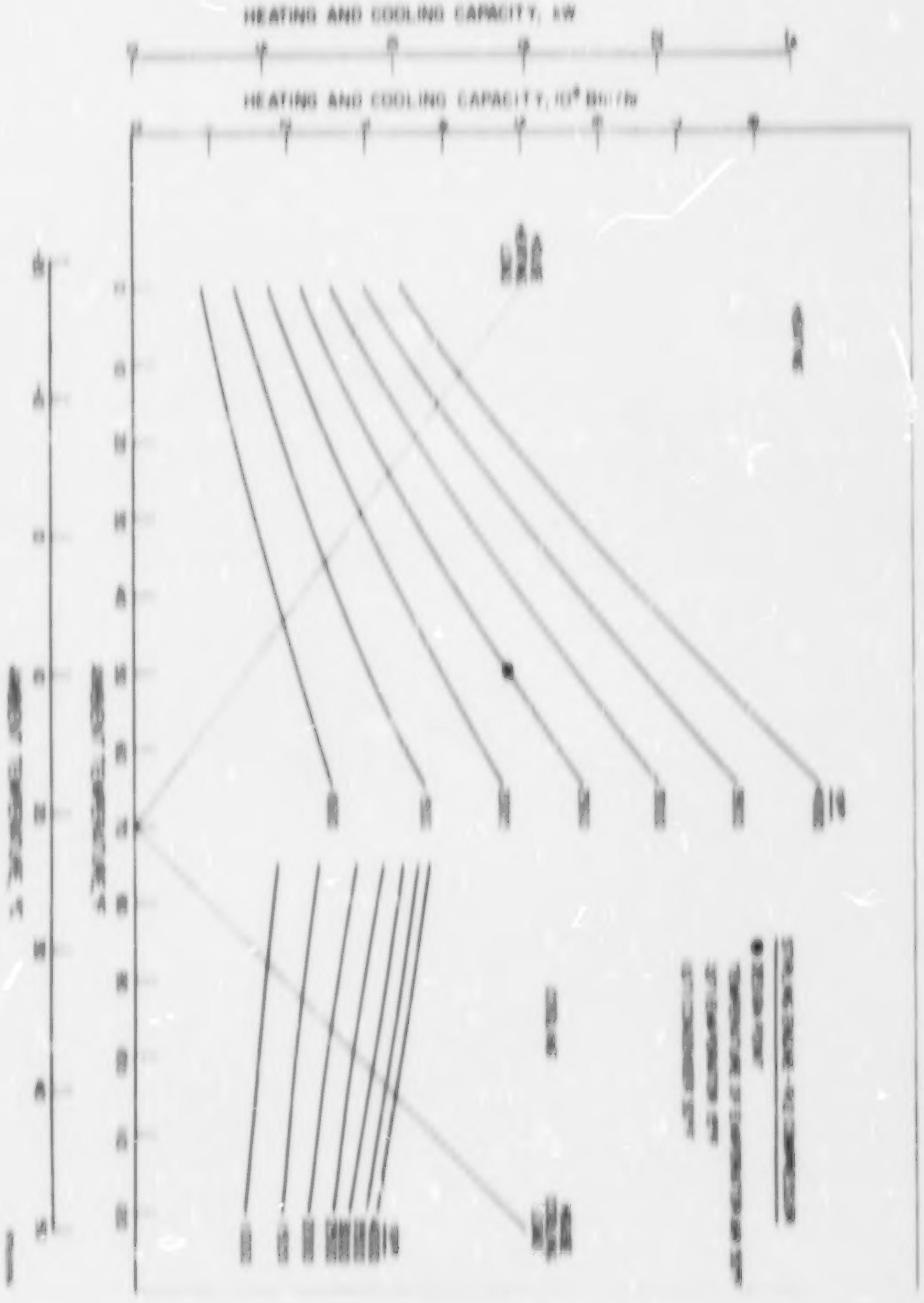


Figure 4. Comparison of system COP's as calculated for design point and off-design operating conditions for a Rankine (R-12) piston heat pump driven by a constant efficiency prime mover.


HEATING AND COOLING CAPACITY, kW
HEATING AND COOLING CAPACITY, 10³ Btu/h

[illegible]

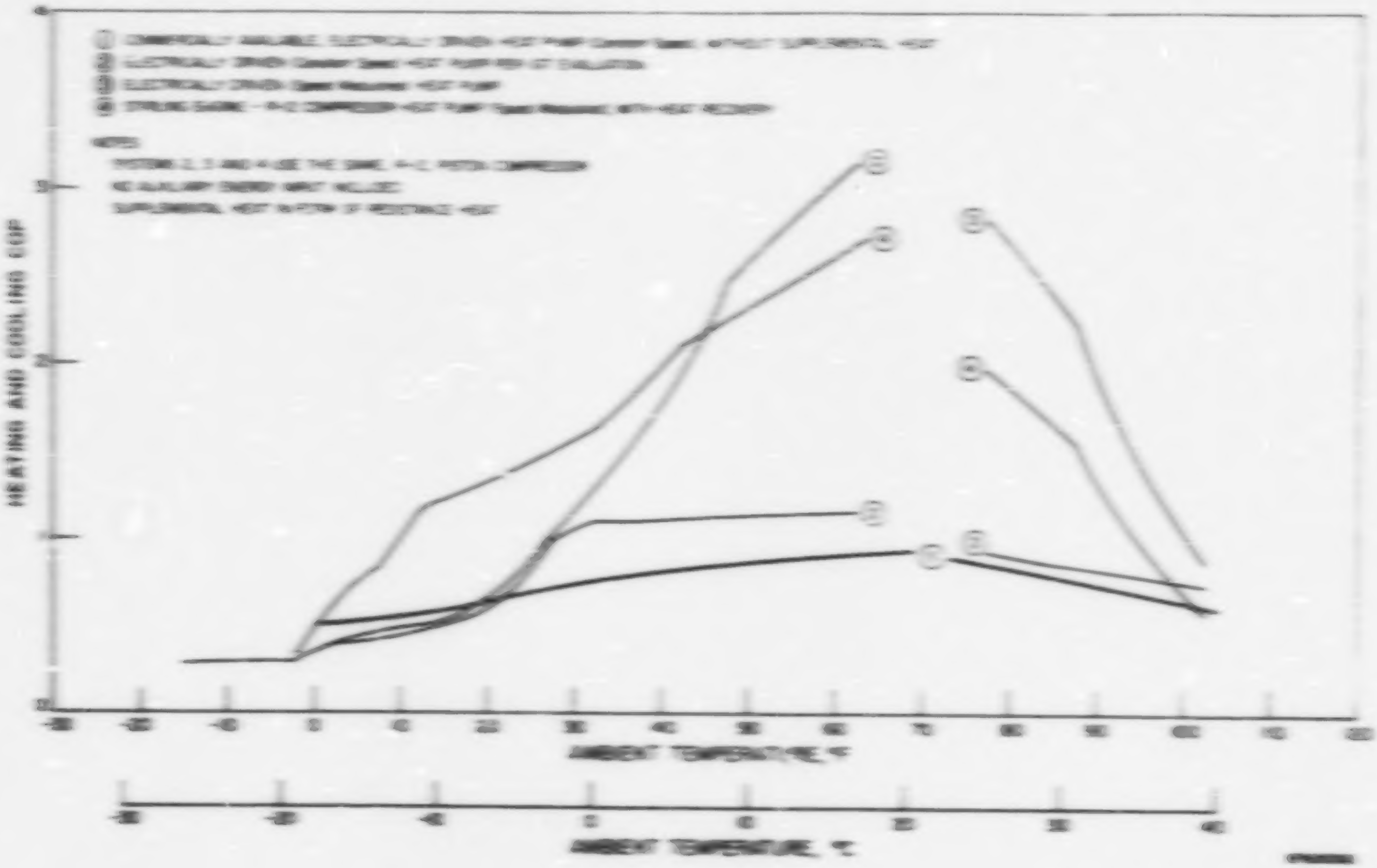


Figure 6. Source energy heating and cooling COP's for selected heat pumps (refer to Figure 5).

Table 2. Performance of selected residential heat pumps for a single-family residence in the Chicago area[a]

| | Heating mode | | | Cooling Mode | | | Year-round | | |
|---|---|---|---|---|---|---|---|---|---|
| | Energy Input, kWh | Savings compared to System A, percent | COP | Energy Input, kWh | Savings compared to System B, percent | COP | Energy Input, kWh | Savings compared to System B, percent | COP |
| Heat supplied or removed from conditioned space | 36,883 | | | 4429 | | | 41,312 | | |
| A. Thermal resistance heating system | 127,182 | | 0.29 | | | | | | |
| B. Electric heat-pump system (constant speed, 3,500 rpm) | 43,856 | 65.5 | 0.841 | 5090 | | 0.87 | 48,946 | | 0.84 |
| C. Electric heat-pump system (speed modulated) | 35,248 | 72.3 | 1.046 | 2015 | 60.4 | 2.198 | 37,263 | 23.8 | 1.108 |
| D. Stirling engine-driven heat pump system (speed modulated plus heat recovery) | 24,721 | 80.6 | 1.492 | 2917 | 42.7 | 1.518 | 27,638 | 43.5 | 1.49 |

[a] Supplemental heat in form of resistance heating; total cooling season, 1,287 hr; total heating season, 5,853 hr; same piston, R-12 compressor used for systems B, C, D; auxiliary energy input not included.

Table 3. Total annual emissions for selected heat pumps serving a single family residence in the Chicago area

| | Heat pump system | | | | | |
|---|---|---|---|---|---|---|
| **Pollutants** | Electric (constant speed, 3,500 rpm)[a] | | Electric (speed modulated 1,000-4,000 rpm)[a] | | Stirling engine-driven (speed modulated plus heat recovery) | |
| | lb/$10^6$ Btu | lb/yr | lb/$10^6$ Btu | lb/yr | lb/$10^6$ Btu | lb/yr |
| Particulates | 0.1 | 16.7 | 0.1 | 12.7 | -- | -- |
| $SO_2$ | 1.2 | 200.4 | 1.2 | 152.6 | -- | -- |
| $NO_x$ | 0.7 | 116.9 | 0.7 | 89.0 | 1.056 | 98.53 |
| CO | Negligible | -- | Negligible | -- | 1.56 | 153.3 |

[a] Data based on coal-fired generating plant with input of 250 × $10^6$ Btu/hr or more.

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# DEVELOPMENT AND APPLICATION OF AN OPTIMUM DISTILLATE OIL BURNER HEAD FOR RESIDENTIAL FURNACES*

L. P. Combs, W. H. Nurick, and A. S. Okuda†

## Abstract

*Experimental combustion research techniques have been used to develop an optimum, low-emission, high-efficiency head for conventional high-pressure atomizing distillate oil burners such as are used in residential space-heating furnaces and hydronic boilers. Application of the optimum oil burner head would offer both significantly reduced consumption of fuel oil and reduced emissions of air pollutants, particularly oxides of nitrogen. Current research is described which is directed toward applying the optimum head in two complementary ways. One approach is to commercialize the optimum head immediately for new and replacement OEM burners and for retrofitting existing burners at low cost. The second approach seeks additional improvement by further optimizing furnace components to match the optimum burner head, and so would provide greater benefits after a somewhat longer commercialization period.*

## INTRODUCTION

The U.S. Environmental Protection Agency has sponsored studies over the past few years to document the emission of air pollutants from existing residential and commercial oil-fired space-heating equipment (refs. 1,2). Concurrently, the EPA has also supported applied research programs to determine the effects of design and operating parameters on exhaust gas emission (refs. 3,4,5). These and related studies have shown that substantial reductions in total emissions from furnaces can be realized by applying combustion control technology, such as flue gas recirculation, staged combustion, and advanced burner designs.

In addition to providing low levels of pollutant emissions, new technology for residential furnaces should also provide some substantial increase in overall thermal efficiency. This would provide the economic incentive for homeowners to replace antiquated equipment by insuring capital recovery within a reasonable number of heating seasons. Equally important is the potential for conserving energy by reducing residential consumption of clean fossil fuels. Thus, the dual benefits of improving air quality and conserving the Nation's dwindling energy resources are strong incentives for timely development of advanced technology for residential heating systems.

This paper describes a series of related research investigations, which began with the application of experimental combustion research techniques to the optimization of conventional, high-pressure atomizing oil burners. Optimization was with respect to minimizing pollutant emissions and improving thermal efficiency, and resulted in design criteria for the burner head. Continuing work in progress is in two directions: (1) optimizing the application of the optimum burner head by determining effective burner/firebox matching criteria and applying them in a prototype furnace and (2) evaluating the feasibility of commercial production of the optimum head for installation in new furnaces and for retrofitting old ones.

## BACKGROUND

Some typical residential oil-furnace emission and efficiency performance data are summarized in table 1. Data on cycle-averaged emissions were abstracted from references 2 and 4. The existing furnace population consists of a broad mixture of burner and firebox types and ages so that its average emissions of incomplete combustion products (CO, UHC, smoke, and particulates) are slightly higher than the representative values for current new furnaces.

An $NO_x$ emission goal of 0.9g $NO_2$/kg fuel burned was established by the EPA as one that is both acceptable from an air quality standpoint and achievable by application of blue-flame burner technology. However, blue-flame burners characteristically have start transient problems which have prevented them from being developed commercially, so it was hoped that the goal could also be attained by conventional burners.

Wide ranges of thermal efficiency estimates for the existing residential furnace population may be found in the technical literature. Those listed in table 1 are representative of the midrange and are generally consistent with the flue gas $CO_2$ concentrations (or excess air levels) reported in references 2 and 4. Recognizing that gross efficiencies, based on the higher heating value of the fuel, are about 5 to 7 percent lower than net effi-

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Table 1. Typical residential oil furnace data

|  | Average of existing furnace population | Average of current new units |
|---|---|---|
| Cycle-averaged emissions |  |  |
| Smoke (bacharach scale) | < No. 2 | < No. 1 |
| CO | < 0.6 g/kg fuel | < 0.3 g/kg fuel |
| UHC | < 0.08 g/kg fuel | < 0.06 g/kg fuel |
| Particulates | < 0.3 g/kg fuel | < 0.2 g/kg fuel |
| $NO_x$ | < 2.5 g/kg fuel | < 2.5 g/kg fuel |
| Thermal efficiencies (net) |  |  |
| Steady-state | 65 to 75 percent | 75 to 80 percent |
| Cycle-averaged | 50 to 60 percent | 65 to 70 percent |

ciencies, it may be estimated that fuel utilization efficiencies potentially might be increased by as much as 35 to 40 percent. Achieving such large gains, however, would entail very significant departures from current design concepts, and manufacturing, marketing, and utilization practices. Considerably larger heat exchangers would be needed to cool flue gases to near room temperature and condense their combustion-generated water vapor. A number of problems would arise immediately, e.g., inadequate firebox draft, need for corrosion-resistant furnace and flue construction materials, condensate disposal, and noncompetitive initial costs. For these reasons, it was deemed appropriate for the current research to address efficiency gains achievable by less drastic modifications of existing commercial technology, i.e., improvements that can be achieved relatively near-term and remain cost-competitive in the marketplace. A target value of 10 percent or greater efficiency increase was thus selected.

### *Reducing Pollutant Emissions*

When clean fuels, such as natural gas and No. 2 fuel oil, are burned in residential space-heating equipment, two classes of combustion-generated air pollutants are emitted, viz., incomplete combustion products (CO, UHC, and smoke) and oxides of nitrogen. The two classes are similar in some respects. Their concentrations in the flue gases are usually very low, so that their production does not significantly affect combustor performance or thermal efficiency, and their concentrations usually are not particularly close to those representative of thermal equilibrium, but are more likely to be determined by poorly controlled features of combustion, viz., regions of poor mixing, spray/combustor wall interactions, size and strength of recirculation eddies, and flame-zone cooling phenomena. These characteristics tend to obviate quantitative analytical characterization of the pollutant emissions; as a result, such characterizations are usually studied experimentally. Conversely, the two classes are dissimilar in some respects, principally because their usual concentrations lie on opposite sides of equilibrium. Thus, for example, NO production is enhanced by higher temperatures and longer flame-zone residence times, both of which tend to drive the hydrocarbon combustion processes to completion and reduce carbonaceous emissions.

### *Improving Thermal Efficiency*

The greatest source of thermal inefficiency in residential space-heating equipment is the convection of heat up the flue. When the burner is being fired, exhausted combustion product gases carry off substantial sensible heat as well as the heat of vaporization of combustion-generated water vapor. These losses can be reduced by decreasing the excess air level and by extracting more heat, i.e., lowering the flue gas temperatures. Steady-state net thermal efficiencies might be raised by 5 to 10 percent before furnace operation is constrained by pollutant formation, low draft, and condensation (corrosion) problems.

Also, while the burner is being fired, most installations use heated, humidified, living-space air for both burner combustion air and barometric draft control air. Although the resultant heat losses are not charged against furnace thermal efficiency, fuel utilization may be raised by 10 percent or more by using a sealed air system to bring in outdoor ambient air for these uses (ref. 8).

When the burner is not being fired, a natural draft flow of air through the burner, firebox, etc., continues to extract heat from the furnace and convect the heat up the flue. This mechanism can reduce net thermal efficiency by as much as 5 percent. These draft air heat losses are a major aspect of the transient heat losses that cause cycle-averaged efficiencies to be lower than steady state. The lower the draft air loss, the less sensitive is cycle-averaged efficiency to variations in cycle duration and fractional burner on-time. Draft air heat losses can be eliminated by providing a positive shutoff device in the combustion air supply. They can also be reduced or eliminated by firing the burner more nearly continuously, e.g., by using modulated-flow or high/low/off burner control. No thermal efficiency advantage can be realized with such control schemes, however, because the flue gas temperatures vary enough during modulation to offset any reduction or elimination of draft air losses.

Heat conducted to the exterior cabinet of a furnace is radiated and convected to the surroundings. Although treated as a furnace loss, this heat, in some installations, may contribute directly to heating the residence and may not be a true heat loss. These furnace-setting losses average about 1.5 to 2 percent for warm-air furnaces. They are higher (3 to 3.5 percent) for hydronic boilers, because component temperatures are more nearly constant during standby than are those in warm-air units. Reduction of these losses nominally depends upon a straightforward economic tradeoff of fuel economy vs. more expensive insulation, although manufacturers must also be concerned about first-cost competition.

The electrical energy expended in operating furnaces amounts to no more than 2 to 5 percent of the net heat of combustion of the fuel. Nevertheless, minimization of electric power consumption is a worthwhile goal because electricity costs the homeowner more than fuel oil and because there is a factor of 2.5 to 3 times as much total energy savings when the inefficiency of the electric generating plant is considered.

To maximize furnace thermal efficiency without departing substantially from current manufacturing and installation practices, the following measures should be effected:

1. Design the burner/combustion chamber combination to operate pollution-free at low excess-air levels, e.g., 10 to 15 percent excess air (13.5 to 13.0 percent $CO_2$ in the flue gases (dry basis)).

2. Lower flue gas temperatures as much as possible. The minimum practical temperature is probably around 200° C (392° F).

3. Employ sealed air systems for combustion air and barometric control. Filter the combustion air to prevent long-term degradation of performance.

4. Close the combustion air supply during standby.

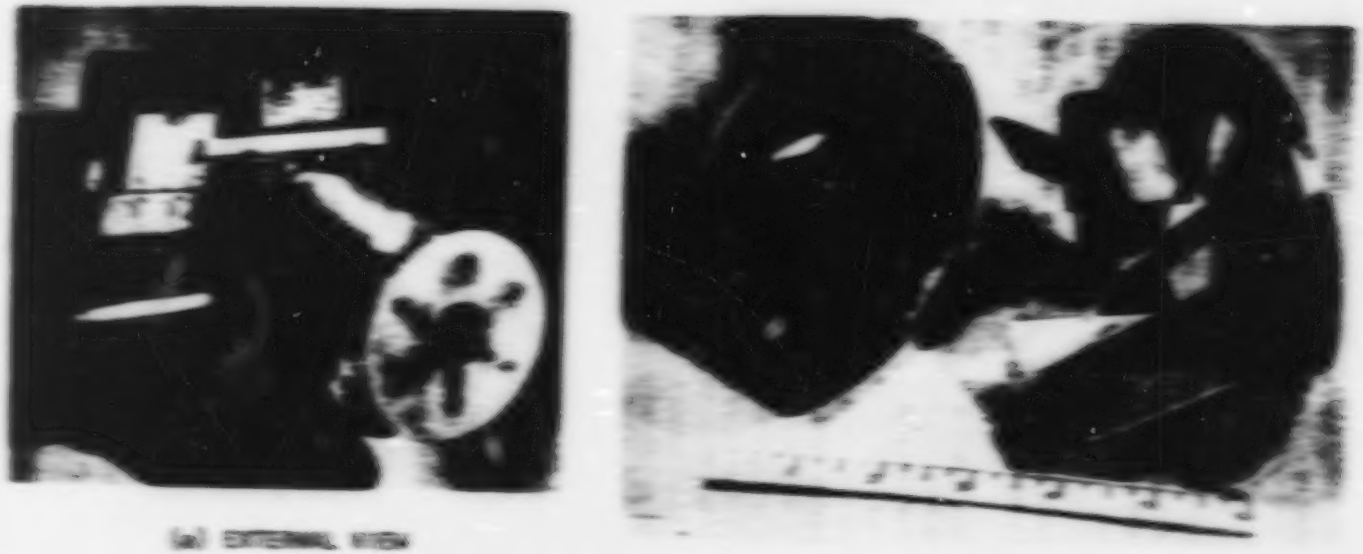
5. Effect savings in electrical power consumption. Areas to consider are proper matching of drive motors to air fans and fuel pumps, interrupted-spark rather than continuous-spark ignition systems, and solid-state ignition and control circuits.

## EXPERIMENTAL STUDIES

### *Oil Burner Optimization*

The initial segment of the oil burner and furnace investigations was concerned with reducing the emissions of pollutants from conventional oil burners. The research results have been fully reported by Dickerson and Okuda (ref. 5) so are only briefly summarized in this paper.

Advanced methods for flow visualization and for measuring atomization, spray-gas mixing, gas-gas mixing, and reaction product concentrations in flames were used to study oil burners and combustion chamber designs that are reasonably close to current conventional commercial practice. Commercially available OEM oil burners representative of current technology were first tested in several sizes to determine their atomization characteristics and the spatial distributions of flow velocities, air/fuel ratios, and reaction species concentrations that they establish within a combustion chamber. The objective was to relate burner emission behavior to specific design concepts and design parameters. Burner design features important to pollutant emissions were identified and "versatile" research burners, provided with continuous adjustability of these features, were built in two sizes. These research burners were fired in a range of refractory-lined and cooled-wall combustion chambers to



(a) EXTERNAL VIEW

(b) OPTIMUM HEAD

Figure 1. Optimum 1 ml/s (gph) oil burner.

determine, principally, optimum combinations of values for their variable design parameters and, secondarily, combustion chamber design attributes supportive of low emissions and high efficiency. Optimum combinations were found which, when fired in comparable combustion chambers, reduced emissions of oxides of nitrogen ($NO_x$) by up to 50 percent with acceptably low emissions of CO, smoke, and unburned hydrocarbons, and without impairing achievable thermal efficiency. It was found that $NO_x$ emissions were about 50 percent lower when the optimized research burners' axes were aligned with the combustion chamber axis (tunnel fired), rather than made perpendicular to it (side fired).

Two sizes of fixed-geometry "optimum" burners were then built and tested to corroborate the versatile research burner results. One of the burners was sized for a nominal firing rate of 1 ml/s (gph)[1] (fig. 1(a)), which is typical of burners for residential oil furnaces. The key design parameters for optimizing the burner were confined to the burner head, an internal view of which is shown in figure 1(b), namely, the swirl vane size, or effectivity, the swirl vane angle and the discharge choke diameter. With sufficiently large swirl vanes, radially disposed vanes canted 25 degrees from the burner axis were optimum, irrespective of the burner firing rate and excess air level. Conversely, the optimum choke plate opening diameter was found to be proportional to the oil firing rate raised to the 0.4 power (ref. 5).

Other burner components, viz., the housing, blast tube, fuel pump, combustion air fan, drive motor, ignition transformer, CdS flame-sensing cell, and burner control circuitry, were stock equipment supplied with a commercially purchased burner. The stock ignition electrodes were replaced by a smaller-diameter pair compatible with the more restricted space imposed by the swirler vanes. Use of a 1.0-80° A (1.0 gph, hollow cone) Delavan spray nozzle provided good air/fuel spray mixing while minimizing spray impingement on combustion chamber walls.

The pollutant emissions from the fixed-geometry optimum burners did reproduce those measured from the versatile research burners. NO emissions are exemplified in figure 2. It was also demonstrated, by testing this burner in typical residential furnaces, that the optimum burner research results are directly applicable to furnaces.

## APPLICATION OF THE OPTIMUM HEAD

Two complementary approaches are being taken toward further exploration and application of the optimum oil burner head technology. One approach is directed toward immediate applications in new and replacement OEM burners and, possibly, in retrofit kits for existing, installed burners. If found to be feasible, direct commercialization of the optimum head alone would offer prompt, albeit modest, gains in fuel economy and reduced emissions. The second approach is directed toward furnace manufacturer applications in new furnaces. This approach is somewhat longer term but should offer greater gains in both efficiency and emission levels, because it involves further technology improvements.

### *Feasibility of Commercialization*

The feasibility of commercial application of the optimum low-emission oil burner head is being investigated by fabricating prototype heads to simulate those which would be produced by appropriate commercial fabrication techniques, and testing them to determine their durability and whether their emission behavior duplicates that of the preprototype research optimum head.

*Fabrication Techniques.* After cursory consideration of various types of fabrication techniques, three were selected as being potential candidates for commercial production of burner heads. These three methods are (1) iron casting, (2) sheet metal stamping, and (3) injection molding. A comparative evaluation of them was conducted; considered were unit costs, manufacturability, saleability, and design compromises likely to be encountered. A comprehensive summary of the evaluation is given in table 2.

The information in table 2 is essentially self-explanatory. The table is concluded by assigning a numerical ranking to each method as a result of comparing all of the information. Reasons for the ranking are also given in the table. The sheet metal stamping method is clearly the best choice, and iron casting, the preferred second choice. Aside from estimated unit production costs, casting was downgraded with respect to sheet metal stamping because of uncertainty regarding the effects on emissions of anticipated design compromises.

*Prototype Optimum Heads.* A preliminary design was made for a 1 ml/s (gph) optimum head to be made by sheet-metal stamping, and two prototype heads were constructed to that design. (These heads were formed by shearing, machining, and bending operations, rather than by their being actually stamped.) The design layout is shown in figure 3, and figure 4 is a photograph of a prototype stamped sheet-metal optimum head.

*Experimental Testing.* The prototype optimum head is

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[1] 1.00 ml/s = 0.951 gph. The 5-percent difference is neglected in this paper when reference is made to burner firing rates.

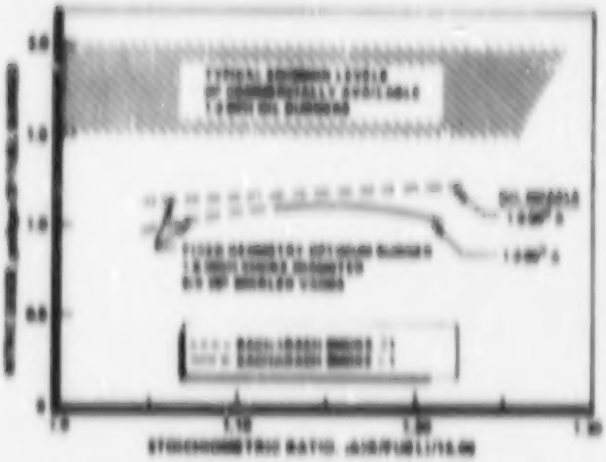

Figure 2. NO emissions comparison (tunnel fired, refractory-lined combustor).

being tested extensively, first in research combustion chambers and later in commercially available furnaces. The research combustor testing will establish correspondence with the preprototype research optimum head, which has been tested extensively in these combustors, as described in the next subsection. In the furnace tests, thermal efficiency and ranges of operability and applicability will be established. This testing will employ three new warm-air furnaces having different firebox constructions and burner orientations. These three were selected as being representative of over 50 percent of the residential warm-air furnaces found in the field.

Currently, the prototype optimum head has been tested only in a side-fired, refractory-lined, research combustion chamber. The measured flue gas pollutant emissions corresponded very well with those from earlier tests of the preprototype head. In less than 50 hours of testing, however, it was apparent that some design modifications will be needed to improve the durability of the head, as there was significant scaling of the face of the choke plate as well as some distortion of its surface, which was apparently caused by nonuniform heating. A stiffening ring made of AISI 321 stainless steel was bolted to the face of the choke plate and testing was continued. The results confirmed that the stamped sheet metal optimum head should be made of 300 series stainless steel to eliminate the scaling and should incorporate substantial strengthening of the choke plate to avoid warpage.

*Future Effort.* Following further evaluation of pollutant emissions when a burner with the prototype optimum head is tunnel-fired in a refractory-lined research combustion chamber, a second series of prototype heads will be fabricated and tested. An improved stamped-sheet-metal design will be used; it will involve either stamping circular stiffening ribs in the choke plate portion of a single-piece head or riveting two stampings together to form a two-piece head. These design changes, together with the material change, are expected to result in a modest increase in the estimated cost of commercial production of stamped heads. Furnace testing will predominate the experimental evaluation of the second series of prototype heads.

*Furnace System Optimization*

This segment of the research is directed toward reducing pollutant emissions, particularly $NO_x$, even further while effecting greater improvements in fuel economy than can be attained by simply adopting the optimum head in existing furnaces. The approach taken was to determine optimum combinations of furnace component designs, using both experimental and analytical techniques, and to design, build, and test a prototype furnace embodying the results.

Table 9. Comparison of optimum burner head commercial fabrication methods

| [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
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| [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |

| [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
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| [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |  | [illegible] |
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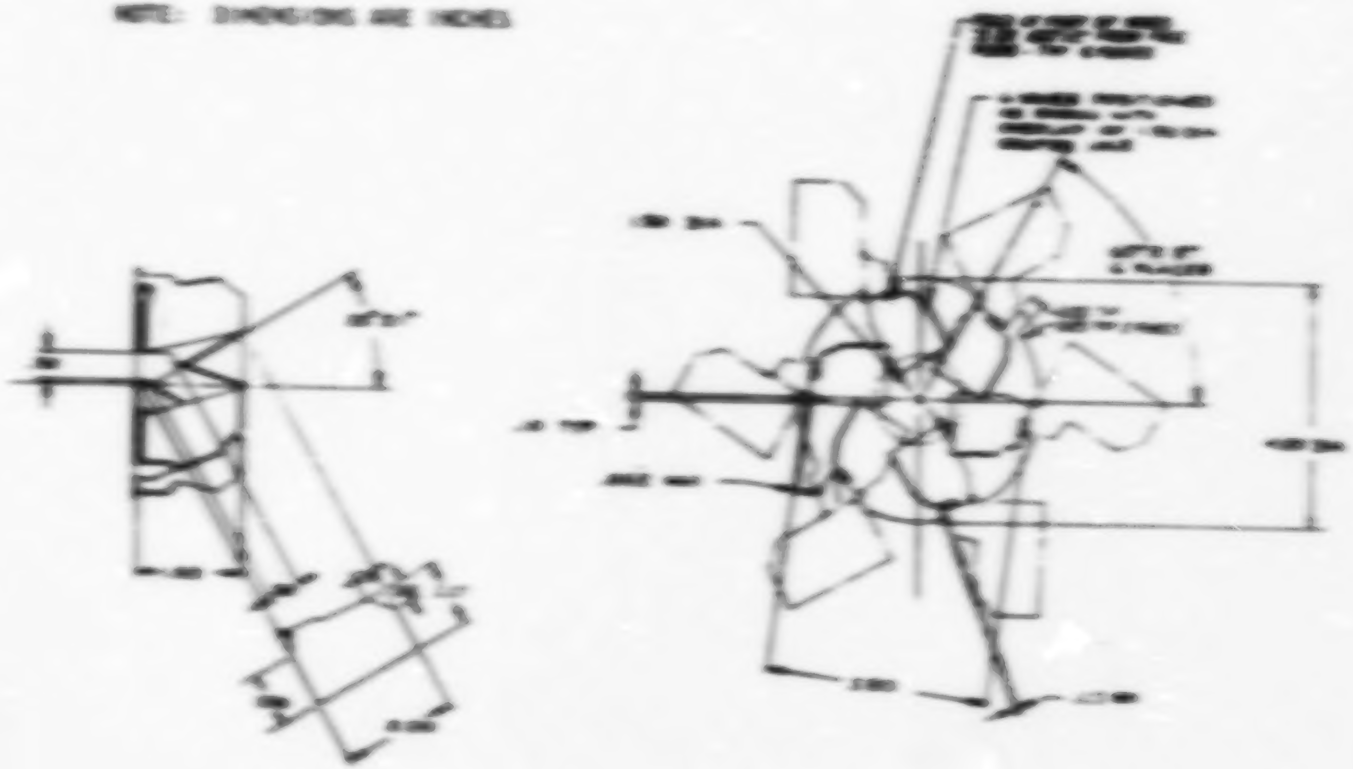
NOTE: DIMENSIONS ARE INCHES

Figure 3. Layout drawing of the stamped formed, sheet-metal prototype optimum burner head (Mark I): AISI 430 steel.

Figure 4. Prototype stamped sheet metal optimum burner head.

It was reasonably well established in the earlier oil burner studies (ref. 3) that an optimized conventional burner can operate reliably at low-excess air levels and produce acceptably low CO, UHC, and smoke. Its NO emission levels, however, were a factor of 2 or more higher than the target reduction below 0.5 g NO/kg fuel, and whether or not the goal could be reached by optimizing the furnace combustion chamber for this burner was an uncertainty.

Therefore, the experimental investigation, which used research combustion chambers rather than typical furnaces, consisted of three separate, but related parts. One part dealt exclusively with the 1 ml/s (gph) optimum burner. This effort sought to optimize the matching of the firebox (combustion chamber) to that fixed burner design. The other two parts branched out to modified burners having, in one case, forced flue gas recirculation (FGR) to the burner air intake and, in the other case, forced combustion gas recirculation (CGR) from the combustion chamber to the burner air intake. These efforts were also focused upon optimizing the burner/firebox combination for low emissions.

The first of these approaches—the optimizing of the combustion chamber matched to the optimum low-emission burner—was found to be the best approach. The experimental investigation with the 1 ml/s combustion gas recirculation (CGR) burner was frustrated by an inability to simultaneously satisfy the NO, CO, and UHC emission goals. Because of these problems and the inherent potential problems of moderately high-temperature mixed gases being passed through the combustion air fan, it was concluded that further work with this burner concept was not warranted.

Tests of the 1 ml/s flue gas recirculation (FGR) burner were more successful and showed good potential for satisfying the emission goals under efficient operating conditions. However, actually achieving all of the emission goals would probably be contingent upon the use of a more complicated burner start sequence to eliminate start-spike emissions of CO, smoke, and UHC, which were experienced under conditions having acceptably low NO.

Thus, it was concluded that the optimized conventional burner in optimized combustion chambers is a preferred choice over both the CGR and the FGR burners. With this choice, it appears that the emission goals can be met, low-excess air levels can be employed, and fewer new or peripheral problems are likely to be encountered in commercializing this burner than with the more complicated recirculation types. Additionally, burner simplicity will insure lower furnace costs with this choice.

*Experimental Apparatus.* The 1 ml/s (gph) optimum burner was cyclically fired in a set of three cylindrical research combustors. In conformity with the testing reported in reference 3, the burner was fired for 10 minutes of 30-minute cycles. The three combustors constituted a matched set, allowing considerable dimensional, structural, and coolant variations. The basic approach for one of the chambers is illustrated in figure 5. Each chamber was a 1.27-m (5.00 ft) long, flanged sec-

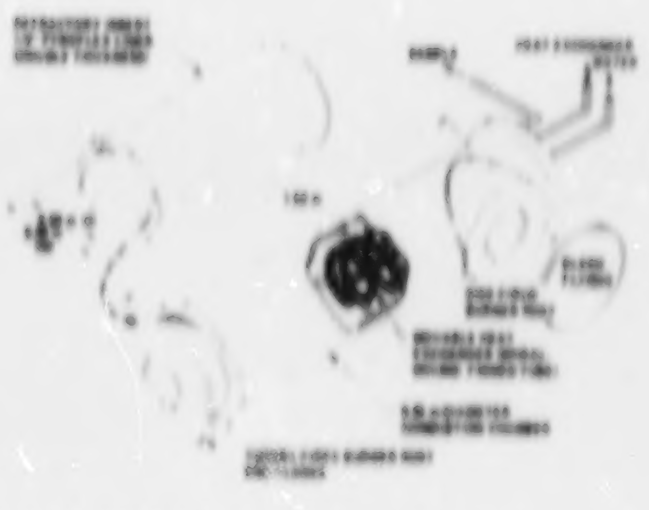

Figure 5. Experimental combustion chamber arrangement.

tion of steel pipe with a stubby, flanged, side-arm section of the same size of pipe attached near one end. The tunnel-fired orientation is illustrated in figure 5, in which the oil burner fits into the annular flange depicted at the left end of the chamber. In this orientation, the side-arm was redundant and so was positioned at the opposite end from the burner and simply blanked off. The steel chamber could be either lined with a refractory fiber insert to form an adiabatic combustion zone, or left unlined and cooled by some means. A movable, spiral-wound, finned-tube heat exchanger (shown inserted in the opposite end of the combustion chamber from the burner) provided effective variation of the combustion zone length. To achieve the side-fired configuration, the combustion chamber was simply turned end for end, with the blank and burner port flanges relocated as appropriate.

Three chamber diameters were selected (table 3) such that addition of refractory linings to the larger two would produce lined chambers having inside diameters comparable with the smaller two unlined chambers. In use, the major axes of the chamber were vertical, with

Table 3. Selected chamber diameters

| Steel pipe ID, m (in.) | Nominal combustion chamber ID, m (in.) | Nominal thickness of Fyroflex, m (in.) |
|---|---|---|
| 0.162 (6.38) | 0.162 (6.38) | -- |
| 0.222 (8.75) | 0.222 (8.75) | -- |
| -- | 0.175 (6.89) | 0.024 (0.93) |
| 0.279 (11.0) | 0.279 (11.0) | -- |
| -- | 0.22 (8.7) | 0.030 (1.18) |

the burner firing vertically upward when tunnel-fired and horizontally when side-fired.

A water-cooled heat exchanger was used to accomplish rapid cooling of the combustion gases as they flowed out of the primary "firebox" portion of any of the combustion chambers. It was intended that the gas temperature be quenched rather rapidly so that changes in heat exchanger position (i.e., firebox length) could be readily correlated with variations in pollutant emissions. The heat exchanger was a spiral-wound, finned-tube assembly designed to fit inside all three combustors and to be positioned anywhere along the length of a chamber.

*Experimental Results.* Data were recorded during 180 tests of the apparatus previously described. In addition to chamber diameter, construction, and burner orientation variations, the heat exchanger position and burner excess air level, or stoichiometric ratio, were varied systematically.

Typical measured emission data are illustrated for one subset of these tests in figure 6. In this example, flue gas pollutant concentrations varied fairly regularly with both stoichiometric ratio and heat exchanger position, although this was not always consistently so.

The results of all the parametric variations tested were synthesized into a tabular summary form amenable to extraction of trends and design criteria. That summary is given in table 4, where the first three columns describe the combustion chamber, and the next three columns list the chamber lengths and stoichiometric ratios for which the pollutant concentrations in the flue gas were acceptable. Few of the NO emissions of the combustor were acceptably low, so conditions that *minimized* NO production are listed under that pollutant. Further, the right-hand column of table 4 lists approximate flue gas NO concentrations at 25 percent excess air (12 percent $CO_2$) for 0.50-m (20-in.) long chambers. It was seen that, with a few exceptions, the combustion chamber designs tested generally failed to achieve the goal of NO < 0.5 g/kg fuel. However, the observed trends in the data support confidence that the goal can indeed be satisfied.

*Combustor Design Criteria.* Combustor design criteria that can be derived from table 4 (and the larger body of data upon which it is based) are subdivided into categories of burner orientation, chamber size, and cooling medium in the following paragraphs.

*Burner Orientation.* Combustion chamber design requirements for insuring acceptable levels of CO, UHC, and smoke emissions are quite similar for the side- and the tunnel-fired burner orientations. That observation held for NO emissions from water-cooled combustors as well. However, NO production in refractory-lined and air-cooled chambers was about 1.5 to 2 times as high in the side-fired orientation as in the tunnel-fired. Ostensibly, this latter phenomenon resulted from substantially longer gas residence times at high temperatures in the

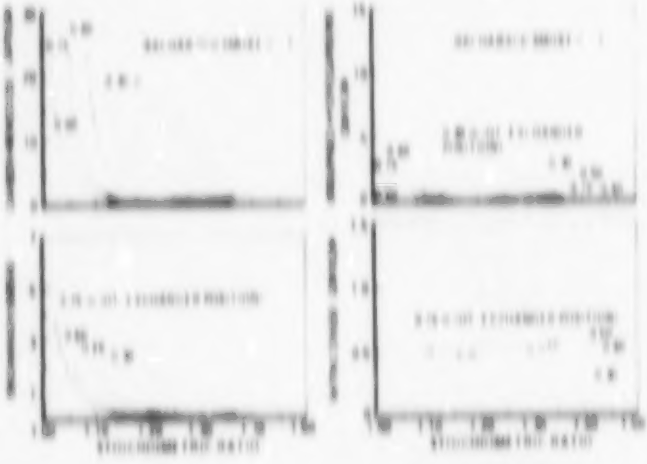

Figure 6. Typical cycle-averaged flue gas emissions.

## Table 4. Summary of results from 1 ml/s (gph) optimum burner/combustion chamber matching experiments

| CHAMBER DESIGN ATTRIBUTES | | | [illegible] | | | [illegible] |
|---|---|---|---|---|---|---|
| [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | |
| [illegible] | AIR-COOLED | [illegible] | ROUGH BURNING THROUGHOUT OPERATING RANGE | | | |
| | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| | WATER-COOLED | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| | INSULATED | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| | | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| [illegible] | AIR-COOLED | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| | | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| | WATER-COOLED | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| | | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| | INSULATED | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| | | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |

stronger and more complicated eddies of a side-fired chamber.

*Combustion Chamber Size.* Chambers smaller than about 0.20 m (8 in.) ID must be refractory-lined to avoid operating with unacceptable combustion roughness. Operation of all designs was acceptable in this regard when their inside chamber diameter was 0.22 m (8-3/4 in.) or larger.

A tendency existed for larger-diameter chambers, with or without insulation, to require longer chamber lengths to achieve comparable levels of carbonaceous pollutants and, concurrently, to produce substantially lower levels of NO. Both phenomena were undoubtedly linked to the ingestion of recirculating combustion gases into the flame zone. For a given burner, larger and stronger recirculation eddies can be established in bigger chambers, reducing the combustion intensity somewhat and lowering the rates of burnout of carbonaceous species. Also, larger diameter chambers have greater wall areas for convective and radiant transmission of heat from the flamezone, which reduces peak flame temperatures somewhat. Increased average gas residence times should produce opposing trends for both NO production and carbon burnout, which could help account for some anomalies in the data. Also, the steady-state recirculation and radiation effects may be partially masked by starting transient effects, particularly with respect to smoke and UHC data.

Short combustion chambers generally were more favorable for low NO but, if they are too short, the fuel may not be completely burned before combustion reactions are quenched in the heat exchanger. A combustor length of 0.5 m (20 in.) is a suitable compromise for most of the chamber designs tested. Slightly shorter chambers might be appropriate if refractory linings were to be used.

*Chamber Cooling Medium.* Refractory-lined combustion chambers generally exhibited less combustion roughness and less sensitivity to starting conditions but also produced higher NO concentrations than did cooled-wall combustors. The air-cooled, side-fired configuration had better starting characteristics (but higher NO) than did the air-cooled, tunnel-fired chamber. Water-cooling appeared to be preferable to air cooling, particularly because of lower side-fired NO levels but also because of smoother starting and more consistent CO and NO emission results. The water-cooled chambers in shorter lengths, however, were prone to produce excessive CO.

It was inferred that the key effect of both air- and water-cooling is the reduction of flamezone temperatures that results from removing heat from the combustor walls. The 0.279 m (11 in.) diameter of the water-cooled combustor, which met all emission goals, had approximately 30 percent of the heat of combustion of the fuel extracted from the firebox. The single "forced draft" air-cooled chamber was designed to duplicate that heat removal rate, whereas considerably less effective natural convection prevailed in the other air-cooled configurations. That forced-draft, air-cooled chamber, however, had an intermediate 0.25 m (10 in.) ID. Its flue gas NO concentrations were approximately midway between those from the 0.203 m (8-in.) and 0.279 m (11-in.) ID water-cooled combustors, indicating that forced-draft, air-cooling can be just as effective as water-cooling in controlling NO emission levels.

*Optimized Combustors for the 1 ml/s (gph) Optimum Burner.* To reduce NO emission levels below 0.5 g/kg No. 2 fuel oil burned while maintaining acceptably low carbonaceous pollutant emissions during operation at low excess air levels (10 to 15 percent), the 1 ml/s (gph) optimum oil burner should be fired into a combustor having the following design attributes:

1. Cooled walls, with either water or forced-draft air coolant, which extract approximately 30 percent of the heat of combustion of the fuel from the flamezone. It is also important to design for nearly uniform inside wall temperatures and for retention of elevated wall temperatures during standby periods.
2. The ID of the combustor should be 0.28 m (11 in.) or greater. (It is inferred that NO emission levels will continue to go down as diameter is increased above 0.28 m (11 in.), but this hypothesis has not been tested.)
3. The effective combustion chamber length, from the burner end to the location where the furnace heat exchanger begins to quench the combustion gas temperature rapidly, should be greater than 0.5 m (20 in.) and perhaps as long as 0.75 m (30 in.).
4. The combustor may be either side-fired or tunnel-fired, whichever is convenient for a particular furnace or boiler design.

*Conceptual Prototype Furnace Designs.* Preliminary conceptual designs were laid out for a prototype warm-air furnace and a prototype hydronic boiler, each embodying the preferred approaches previously discussed for improving efficiency and reducing emissions. Each design concept layout was discussed with one or more representatives of a manufacturing company that makes and markets residential space-heating equipment. Thereafter, the designs, the manufacturer's comments, criticisms and suggestions, and appropriate design modifications were reviewed with the EPA project officer preparatory to selecting one of the designs for fabrication and experimental evaluation.

The preliminary conceptual designs are illustrated and briefly described. Greater detail is given in reference 7.

*Conceptual Design: Warm-Air Furnace.* A conceptual design layout for a prototype low-emission, improved-efficiency, warm-air furnace is shown in figure 7. It is based upon modifying an existing, commercial warm-air furnace[7] to accommodate an optimized, low-emission oil burner with sealed air supply and a large, air-cooled, steel combustion chamber. This approach allows key concepts to be tested without the expense and delay of designing and fabricating most furnace components. Further, it insures that commercially practical heat exchangers, air filters, blowers, cabinets, and controls are imposed upon the concept to be evaluated.

In figure 7, the burner vestibule is a closed volume supplied with combustion air through a small filter from an external, sealed air system. Not shown is a positive shutoff device for this air when the burner is inactive; this device might be a solenoid-actuated butterfly valve in the combustion air inlet line.

The combustion chamber is offset slightly toward the back of the furnace to accommodate its large diameter. The chamber is comprised of a standard pipe cap welded to an eccentric reducer whose small end is mated to the furnace heat exchanger. Welded to its outside are many longitudinal fins to enhance transfer of heat to the vertically upflowing, cooling air. The fins also act as a heat sink to help keep the combustion space warm during standby periods.

*Conceptual Design: Hydronic Boiler.* The conceptual design layout for a prototype, low-emission, improved-efficiency hydronic boiler is shown in figure 8. This design is based on substantially all-new construction, principally because no commercially available unit was identified as being readily adaptable to the larger-diameter, water-cooled combustion chamber for the optimum burner.

A horizontal, tunnel-fired, water-cooled combustion chamber was selected because it offers boiler structural and package volume advantages. The horizontal firebox is followed by multiple sequential passes through a water-cooled, fire-tube heat exchanger. Commercially available Turbuflue internally finned tubing is indicated for this service. The combustion chamber and heat exchanger tubes are all attached to the same boiler tube

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[7] A Lennox Model 011-140 furnace was selected.

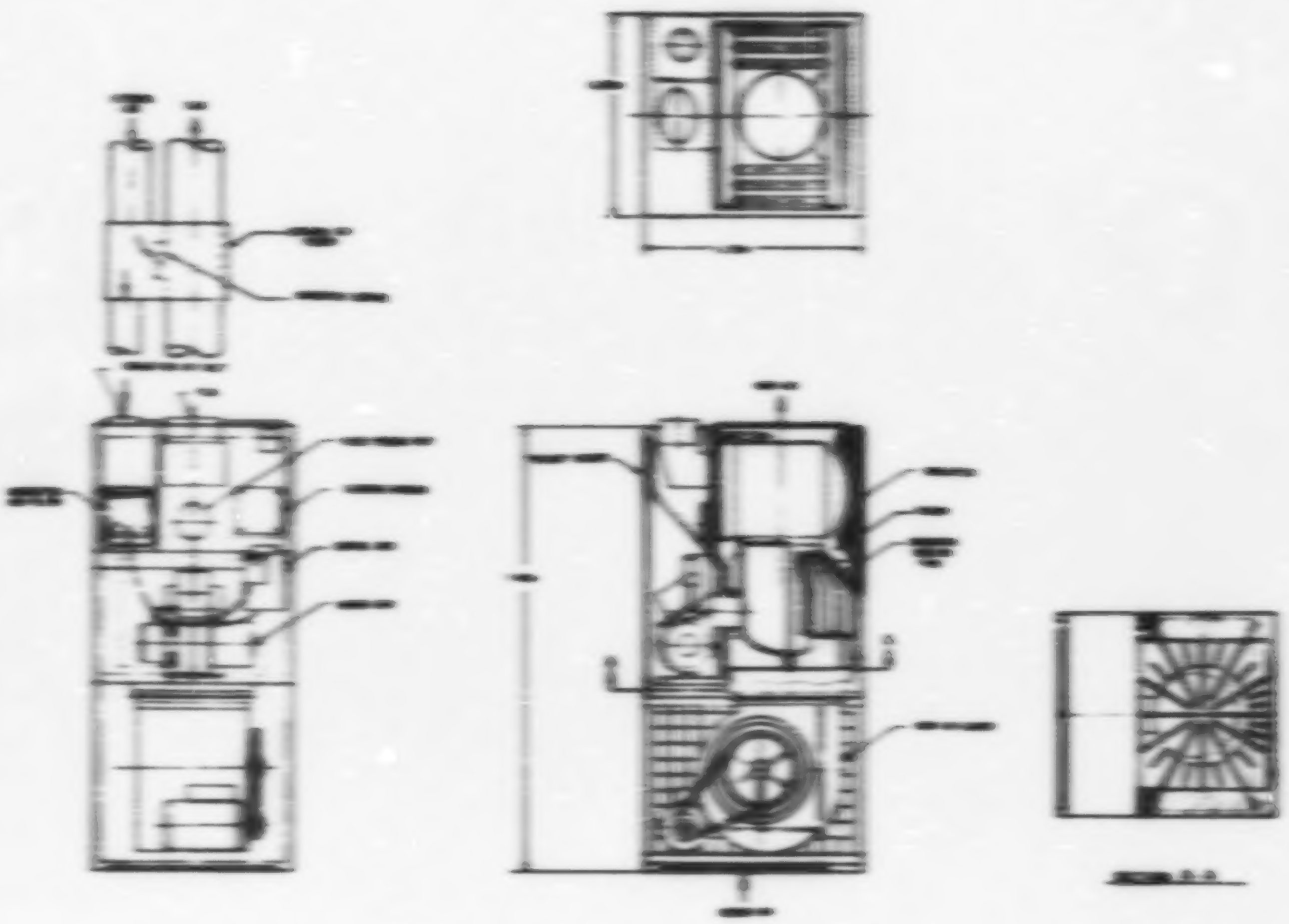
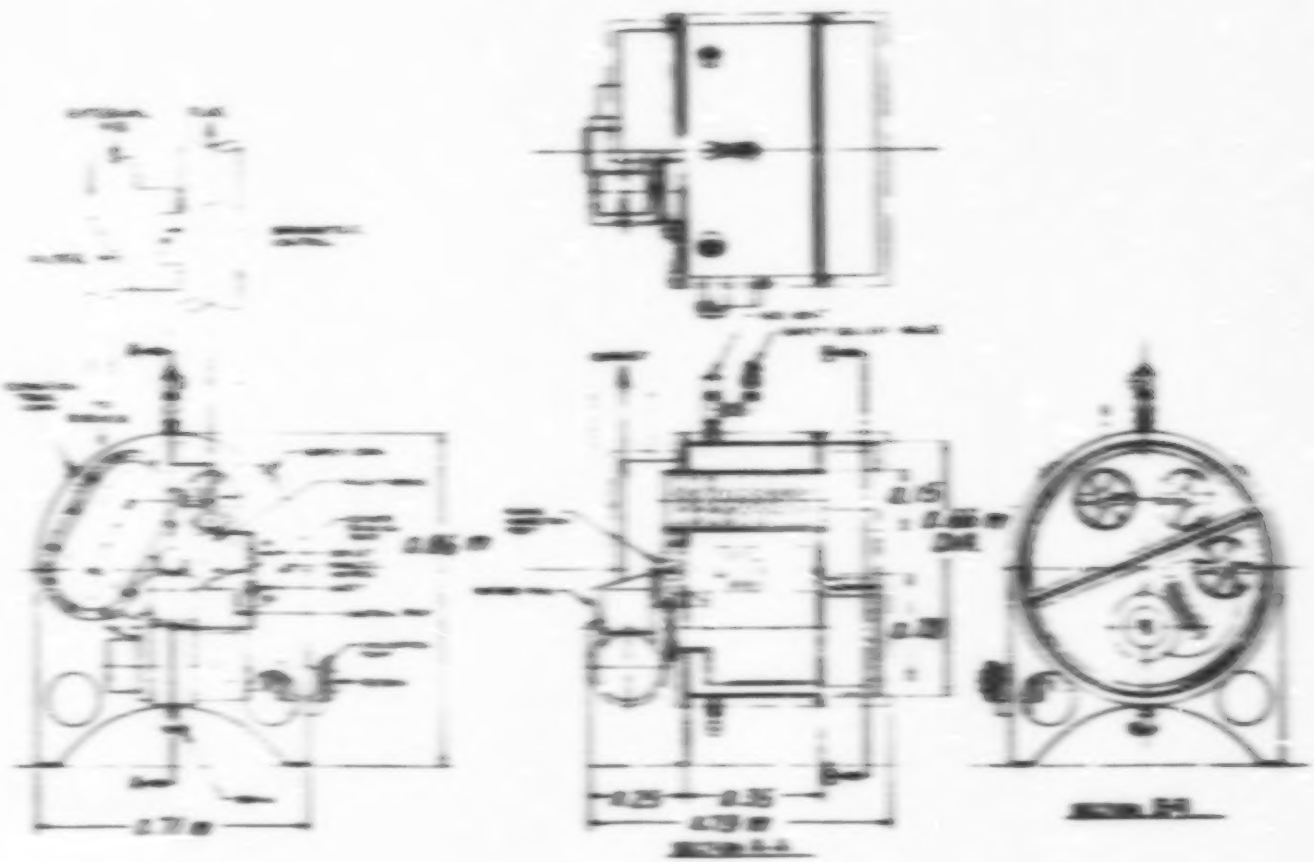


Figure 7. Conceptual prototype: low-emission, warm-air furnace.



0.15
0.66 m
DIA
0.30
0.25
0.35
0.73 m
0.86 m
0.71 m

Figure 8. Conceptual prototype: low-emission hydronic boiler.

sheets. Between the combustion chamber and the first heat exchanger pass, combustion gases are reversed by passage through an insulated 180-degree return manifold, whose volume is considered to be part of the combustion chamber. Similarly, there are 180-degree return manifolds between successive heat exchanger passes.

The conceptual hydronic boiler design also has the usual plumbing and control features needed for installation and operation in a residence, including a tankless coil for heating domestic hot water. Needed, but not shown in figure 8, is an exterior cabinet that should be well insulated to reduce external heat losses.

*Future Effort.* Following comparative assessments of the two preliminary prototype designs, including their potential overall emissions and fuel economy impact, the warm-air system has been selected as the more promising; therefore, a prototype warm-air unit will be built for further study in the continuing work. The data and experiences gained will be applied to the final design of a cost-competitive, commercially producible, warm-air furnace that embodies the derived low-emission, improved efficiency technology.

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# EVALUATION OF THE POTENTIAL IMPACT OF ALCOHOL FUELS ON POLLUTANT EMISSIONS AND ENERGY REQUIREMENTS OF AREA SOURCES

G. Blair Martin[1]

## INTRODUCTION

Stationary combustion sources used in residential and commercial applications can be classified as area sources. Although the pollutant emissions from an individual unit are relatively small, the discharge into the atmosphere is near ground level in populated areas and the number of sources is large. Although residential and commercial sources contribute only about 10 percent of the mass emissions of $NO_x$, the environmental impact may be more significant. In addition, these sources which generally require clean fuels (i.e., natural gas and distillate oil) account for 20 to 30 percent of the stationary source energy usage. In 1972, transportation used about $16 \times 10^{15}$ Btu ($1.69 \times 10^{19}$ J) while residential and commercial heating used about $14 \times 10^{15}$ Btu ($1.48 \times 10^{19}$ J). For the latter category, natural gas provided about 60 percent of the energy, and fuel oil, predominantly distillate, provided the balance. Based on these factors, it appears that both environmental and energy aspects of these area sources require further attention.

Since these area sources require premium quality fuels, the current energy shortage requires an examination of the options that may be available in the future. These options include completely new approaches as well as retrofit or modification of existing systems. The first category includes solar, fluidized bed, and catalytic combustion concepts; however, most of these are in very early stages of development for area source applications and must be considered as potential long term solutions. The second category includes increased use of electrical heating, improved efficiency and emissions performance on conventional clean fuels, and use of alternate clean fuels. These approaches may be amenable to shorter term applications and/or retrofit to existing types of equipment.

The choice of new technologies to be developed depends on a number of factors. From an energy standpoint, the overall efficiency of the process needs to be considered from resource extraction to end use. This is particularly important since the overall efficiency is the result of multiplication of the individual efficiencies of the steps in the process. Cost considerations must include both energy cost delivered to the user and capital costs of the end use device. Evaluation of environmental factors must also include all steps in the scheme from resource extraction, through conversion processes and transportation, to end use. Finally, policy decisions, such as fuel allocation to various users, will play a major role in the future course; however, the decisions should take into account the best available information on the energy, environmental, and economic aspects mentioned above. It is clear that the required analysis of the available options is very complex and beyond the scope of this paper. However, it is possible to identify the need for additional information in technical areas related to energy utilization in the residential and commercial sectors. One of the near-term areas that is of particular interest is the use of alternate fuels. From a practical standpoint, alternate fuels can be used in conventional equipment either directly or with a minimum of modification. This allows consideration not only of the 5 to 8 percent of new installations each year, but also of the vast number of existing units (e.g., about $65 \times 10^6$ residential units).

For application to area sources, only high Btu fuels, which can be economically transported and/or stored, should be given strong consideration. These sources are fired predominantly with clean premium fuels, such as natural gas and distillate oil. The alternate fuels must be clean gaseous and liquid fuels that can be interfaced with current combustion and fuel distribution systems with fairly minor modifications. Synthetic Natural Gas (SNG) should be virtually indistinguishable from the pipeline natural gas and adaptable without change to existing gas-fired equipment. For the distillate oil-fired units, the alternative requiring the least change would be a clean liquid fuel. One candidate is distillate oil derived from coal or shale derived crudes; however, evidence indicates that these oils may contain significant amounts of fuel nitrogen which can produce fuel NO. The technology for controlling $NO_x$ emissions for these high-nitrogen fuels is just developing and may not be readily adaptable to small residential sources. This is one area needing further study. A second class of candidate liquid fuels is the alcohol fuels, predominantly methanol, which are sulfur and nitrogen free. For both types of liquid fuels there are two major questions:

1. What are the combustion and emission characteristics of the fuels, particularly for residential and commercial equipment?

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7. What is the probability that the fuel will be available in sufficient quantity to have a significant impact on area source energy needs?

The emphasis in this paper is on the use of alcohol fuels in residential and commercial combustion systems. A brief summary of information on methanol synthesis is followed by a review of the data on alcohol fuels combustion. Based on this information, emission and efficiency aspects of alcohol fuels combustion in area sources are discussed.

## BACKGROUND

The available information on alcohol fuels covers both sources of supply and combustion properties. Each of these subjects is summarized briefly below.

### *Source of Supply*

The use of alcohol as fuel dates back into the 1800's when methanol was derived from the destructive distillation of wood. The use of alcohols as motor fuels received much attention in Europe during the 1940's. Much of the historical information is summarized by Pleeth (ref. 1), who also reports that $10^6$ gallons of ethanol can be derived from 2,000 acres of artichokes ($4.68 \times 10^{-4}$ $m^3$ per $m^2$).

In current considerations of approaches for obtaining large quantities of alcohol fuels, three possibilities are commonly mentioned. These are: (1) conversion of remote natural gas as a method of transporting energy, (2) synthesis from coal as an alternative to SNG, and (3) generation by bioconversion processes. Most available information deals with the first two, which are discussed briefly below.

*Natural Gas Conversion.* Most chemical grade methanol is made by reforming natural gas followed by methanol synthesis. While this is acceptable for the limited amounts of chemical grade methanol produced, it is not a viable source of fuel methanol. In terms of energy alone, it makes very little sense to take two energy units of a good fuel ($CH_4$) and convert it to 1 to 1.2 units of another fuel.

Therefore, the only logical source of methanol fuel from natural gas is in the situation where the methanol provides a cost and/or energy effectiveness advantage. Duhl (ref. 2) has proposed that remote natural gas be converted into "Methyl Fuel" as an alternative to liquid natural gas (LNG), based on long distance transportation considerations. "Methyl Fuel" is a mixture of methanol with about 10 percent higher alcohols and is produced by a process that Duhl states is simpler than a chemical grade methanol process. The price of "Methyl Fuel" is estimated to range from $0.65 to $0.85 per $10^6$ Btu ($0.616 to $0.84 per $10^9$ J), which is one of the lowest costs for alcohol fuels quoted in the literature. In contrast, Hoogendoorn (ref. 3) has also evaluated the conversion of remote natural gas ($0.40 per $10^6$ Btu ($0.38 per $10^9$ J)) to methanol and concluded that the production cost is $2.55 per $10^6$ Btu ($2.42 per $10^9$ J). He states that the thermal efficiency of methane to methanol is 58 percent.

*Coal Conversion.* An alternate path of particular interest in the United States for producing methanol fuel is via a synthesis gas derived from coal. McGhee (ref. 4) has proposed coproduction of SNG and methanol at 59 and 41 percent, respectively. In this case, the methanol is required to sell as a chemical at $6 per $10^6$ Btu ($5.70 per $10^9$ J); however, this is the result of a decision that the natural gas must be subsidized to sell at $1.48 per $10^6$ Btu ($1.40 per $10^9$ J). Eastland (ref. 5) has studied production of methanol alone from coal and shows a range of cost from $2.50 to $4.00 per $10^6$ Btu ($2.37 to $3.79 per $10^9$ J), dependent on coal cost and method of financing assumed. Jaffe (ref. 6) has reviewed the full range of methanol production technology and concluded that a state-of-the-art plant can produce methanol at $1.58 to $3.06 per $10^6$ Btu ($1.50 to $2.90 per $10^9$ J) with an overall thermal efficiency of 45 percent. For comparison, he listed a refinery price of premium grade gasoline at $2.00 to $3.00 per $10^6$ Btu ($1.90 to $2.85 per $10^9$ J). Finally, Pasternak (ref. 7) estimates the cost of methanol produced by in situ gasification of a low-grade coal at $1.04 per $10^6$ Btu ($0.99 per $10^9$ J) and contrasts this with $1.89 per $10^6$ Btu ($1.80 per $10^9$ J) for methanol produced from a Lurgi synthesis gas. Although there is a wide range of assumptions incorporated into these estimates, it would appear that methanol can be produced at a cost that is reasonably close to conventional fuels and SNG. In addition, the overall conversion efficiency of coal to methanol in the range of 45 to 60 percent exceeds the current conversion efficiency of coal to electricity. Viewed in this way, methanol may have a future as a fuel for area sources if the production facilities are established.

*Environmental Aspects.* The major environmental concern in methanol production is the coal conversion process. Comprehensive analyses for a number of fuel conversion processes have been carried out by Exxon R&E under EPA contract and reported in a series with numbers EPA-650/2-74-009-a to g. Another area of concern is the toxic nature of the methanol itself, and further study is needed to establish the actual health and environmental problems related to handling this fuel.

*Combustion Properties*

Although the data on combustion of alcohols in stationary sources are limited, several recent papers have provided some insight.

*Hot Wall Experimental System.* Data comparing alcohol fuels with two conventional clean fuels in a hot wall experimental furnace are shown in figure 1 (ref. 8). It can be seen that methanol produces 25 to 35 percent of the level of NO from the two conventional fuels. Figure 2, which presents the $NO_x$ emissions as a function of the higher alcohol content, shows that the 10 percent content of higher alcohols in "Methyl Fuel" will result in a small increase in emissions. Finally, figure 3 shows the effect of flue gas recirculation (FGR) on the $NO_x$ emissions. While external FGR is probably not a

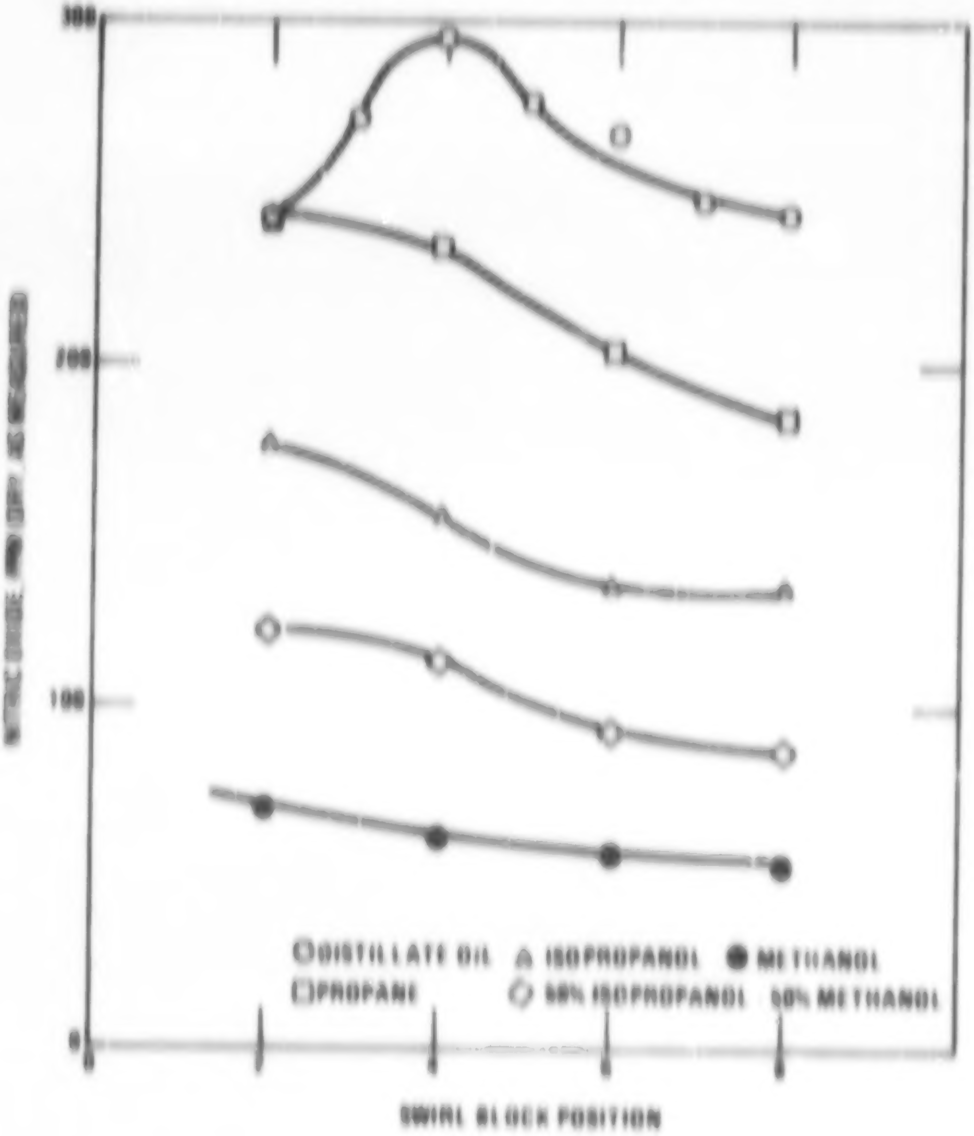

Figure 1. Comparison of baseline nitric oxide emissions for various fuels as a function of swirl parameter.

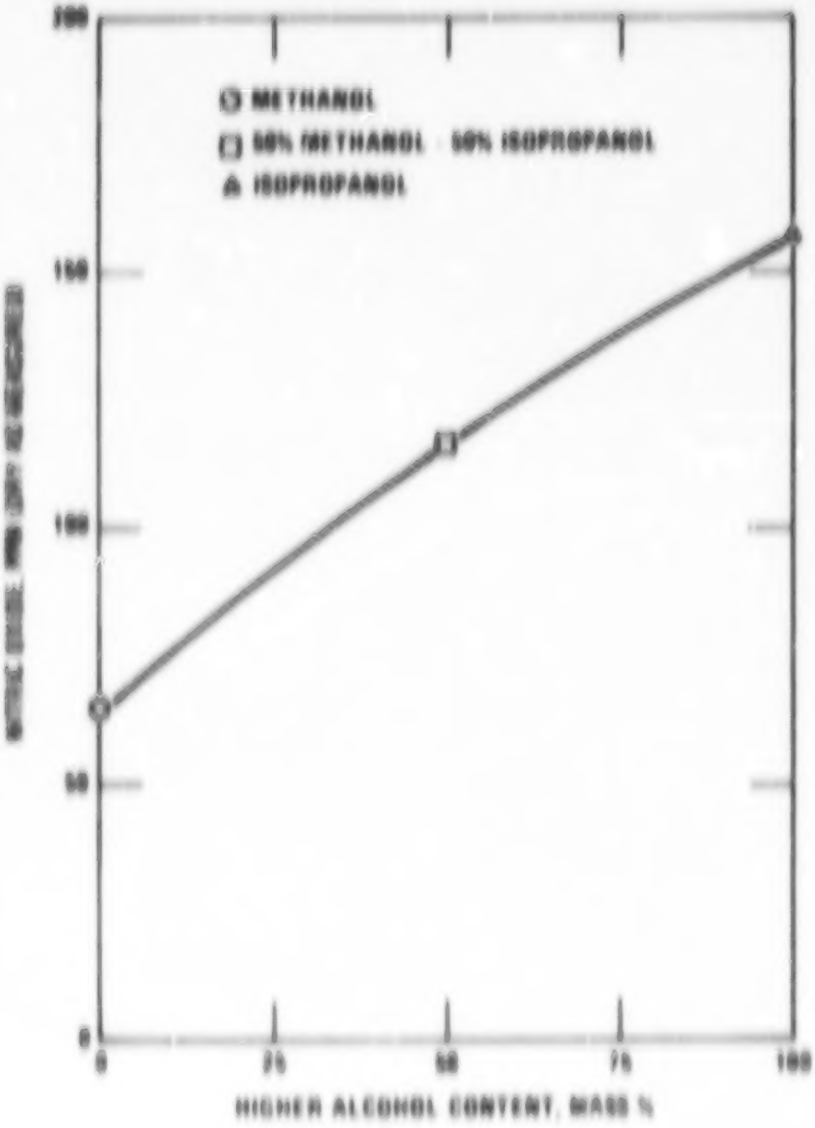

Figure 3. Effect of higher alcohol content on nitric oxide emissions.

feasible technique for small combustion sources, these results indicate that a burner designed to induce internal recirculation of relatively cooler combustion gases may have the potential for a further reduction of emissions. During these tests, the emissions of other pollutant species (e.g., CO, UHC) were small and comparable for all fuels.

*Cold Wall Experimental System.* Results have also been reported for a variety of fuels fired in a cold wall experimental system simulating a package boiler (ref. 8). The system was fitted with a modified commercial dual fuel burner and no problems were encountered using the ultraviolet flame safety system. Figure 4 shows a comparison of the NO emissions for four fuels as a function

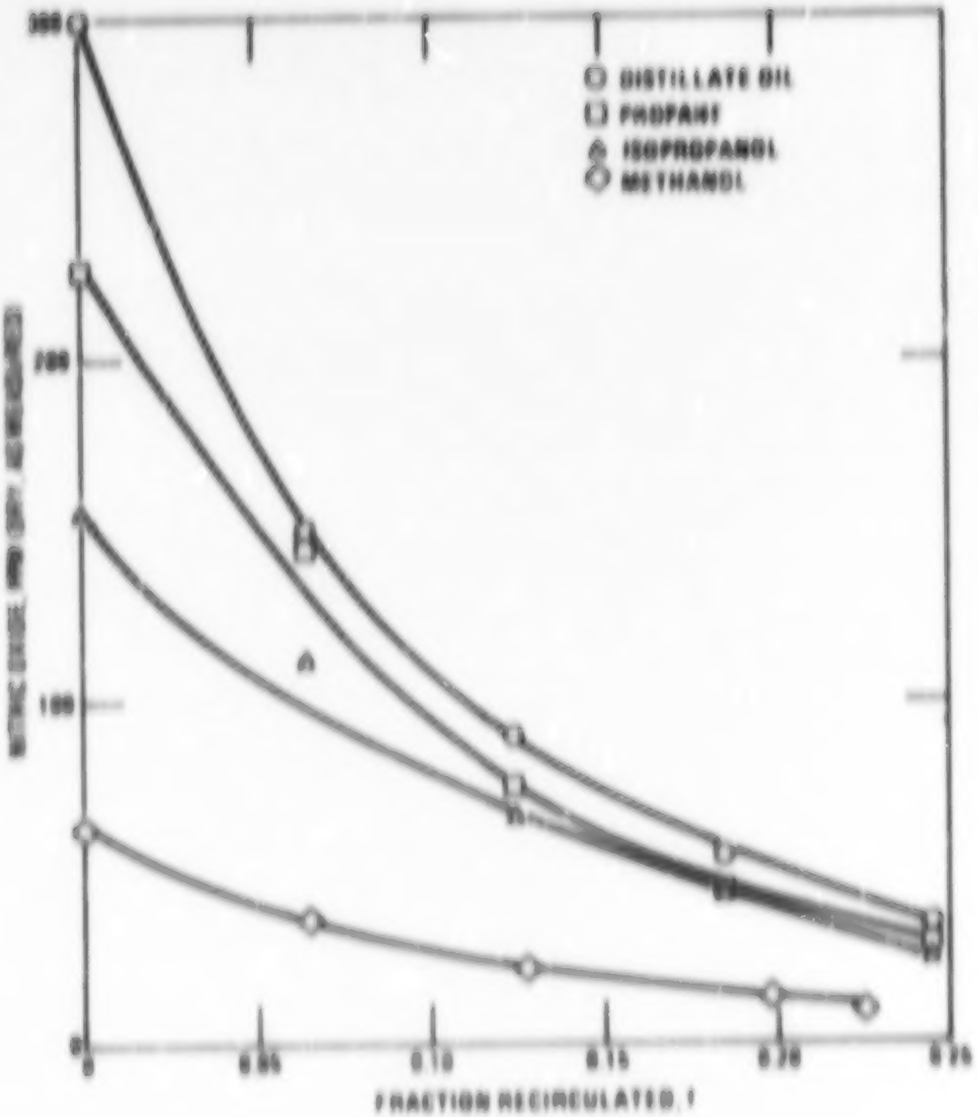

Figure 3. Effect of flue gas recirculation on nitric oxide emissions for various fuels.

of combustion air distribution between the burner primary and secondary channels. It is particularly interesting that the methanol results are not radically different than those from the hot wall system, while the distillate oil emissions are significantly lower. The high level for the residual oil is attributable to fuel NO from the 0.38 percent nitrogen oil.

In addition to these results, Duhl (ref. 8) has also reported results for a cold wall system where the methanol resulted in 25 to 50 ppm NO compared to 100 to 200 ppm NO for methane. These differences from the results above may be attributable to the presence of a hot refractory throat tile in the system reported by Duhl.

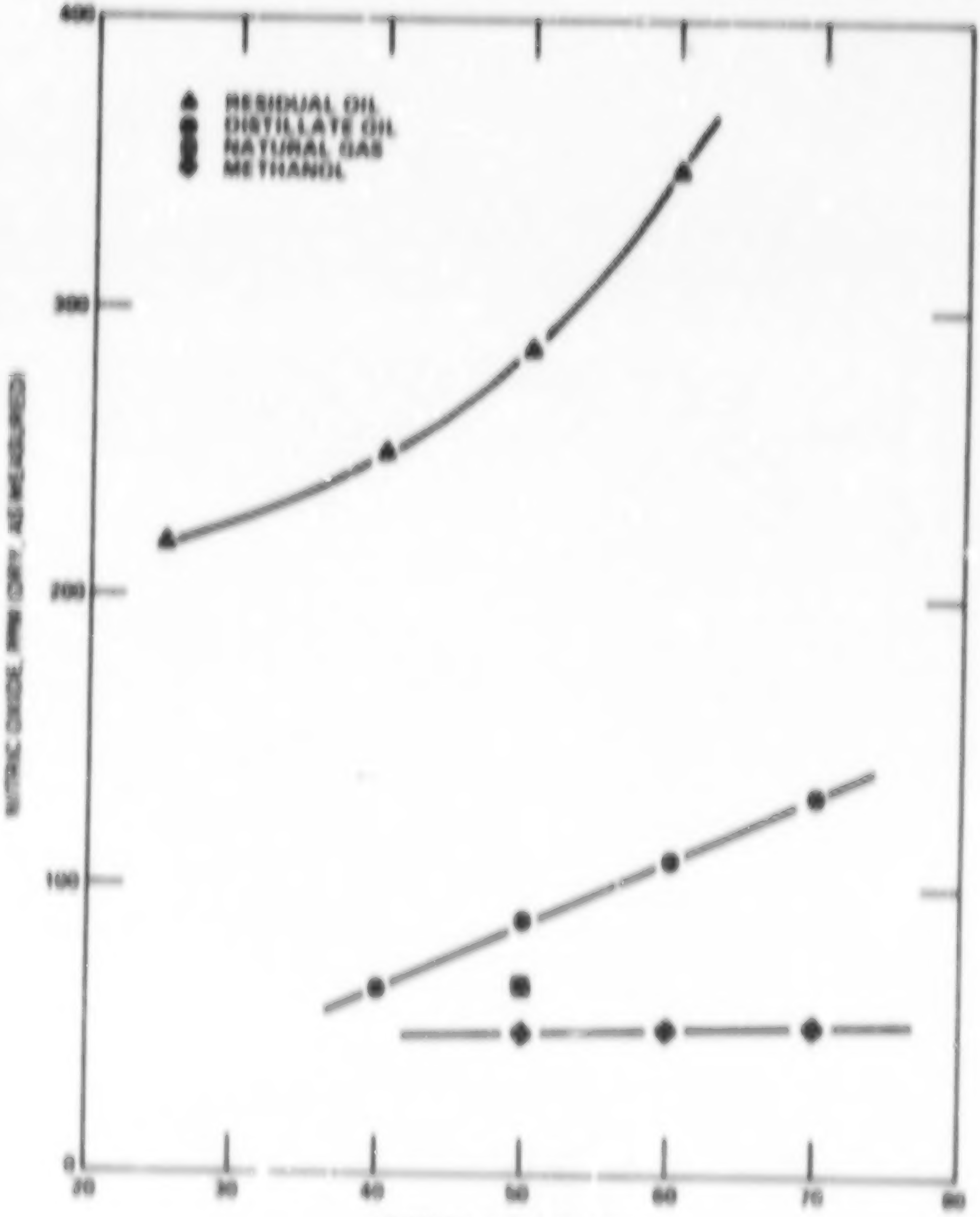

Figure 4. Comparison of baseline nitric oxide emissions for various fuels as a function of burner primary air.

*Practical Systems.* Data on practical systems are almost nonexistent; however, Figure 5 shows data on a 50-MW utility boiler also reported by Duhl (ref. 9). These results show relatively small differences between emissions for methanol and natural gas.

In addition, a field firing of methanol in package watertube and firetube boilers is in preparation on EPA contract 68-02-1498. These tests will provide direct [illegible]

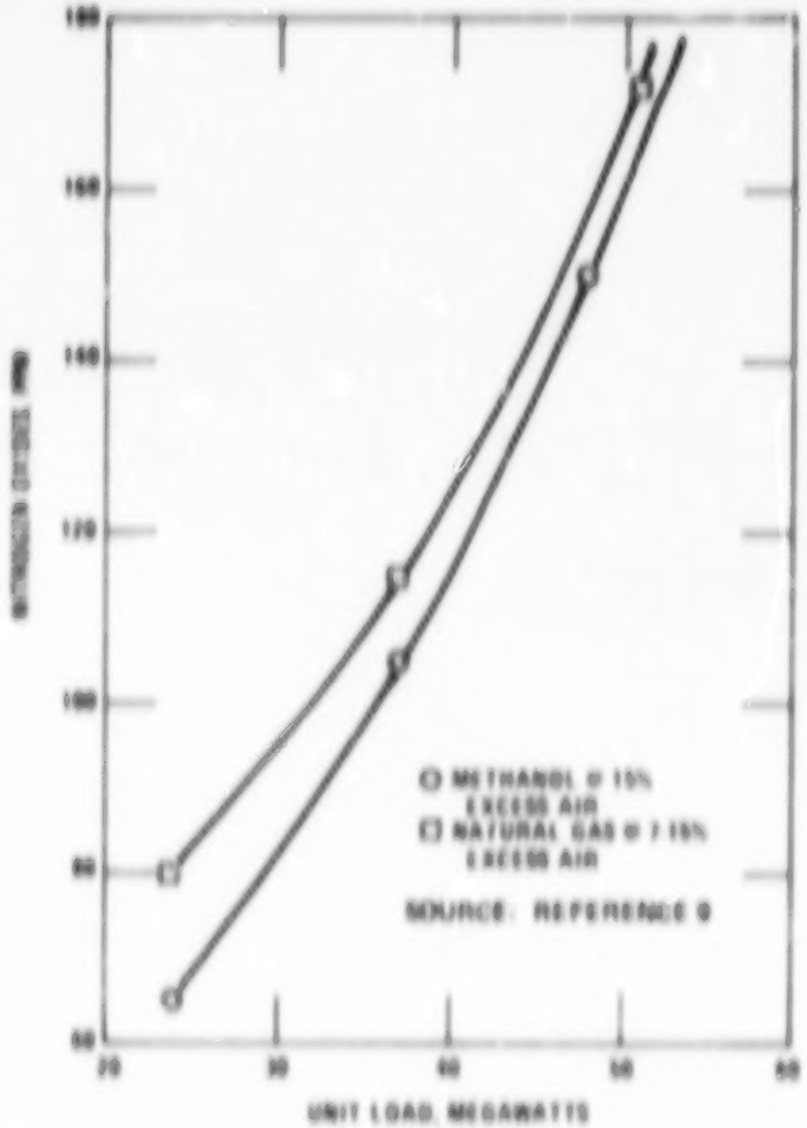

Figure 5. Nitrogen oxides emissions from methanol and natural gas as a function of utility boiler load.

dence on the changes required to fire methanol in existing commercial size package boilers and will also examine the impact on system efficiency.

*Summary.* The major aspects of the combustion data can be summarized as follows:

1. For any given condition, alcohol fuels produce lower emissions of $NO_x$ than distillate oil, methane, or propane.
2. The NO emissions of alcohol fuels increase as the percentage of higher alcohols increases.
3. The low NO emissions for alcohol fuels appear to be a function of the presence and level of oxygen in the fuel molecule, which can be viewed as a diluent carried in the fuel. The operative mechanism appears to be related to thermal effects of the fuel, latent heat of vaporization, and/or decreased flame temperature; however, chemical effects cannot be totally ruled out.
4. The magnitude of the difference between methanol and any conventional fuel is a characteristic of system design; however, the difference appears to be smaller for cold wall systems.
5. The emissions of CO, UHC, and particulates for alcohol fuels were generally the same as, or less than those for the conventional clean fuels tested (propane and distillate oil). Aldehydes do not appear to be a significant problem based on limited data.
6. From a technical standpoint, methanol appears to be a satisfactory fuel for stationary combustion systems.

## DISCUSSION

Although the information for complete assessment of the use of methanol in residential and commercial systems is not available, it is possible to identify potential advantages and/or problems for the two types of systems. These are discussed briefly below.

### *Commercial Boilers*

The type of equipment used in the commercial sector is almost exclusively package boilers generating hot water or low pressure steam. In recent years, the trend has been toward burners capable of firing two fuels (i.e., gas and oil). The flame safeguard system is of the ultraviolet (UV) type and, therefore, is compatible with the requirements imposed by the nearly nonluminous methanol flames. The second consideration for methanol firing is the ability of the fuel nozzle to supply the rated energy input of the boiler. A total of 2.1 volumes of methanol must be fired to achieve an energy input equivalent to 1 volume of fuel oil; therefore, a larger capacity fuel nozzle will be required in most cases. In addition, the viscosity difference between methanol and fuel oil may also influence the required nozzle size. Current evidence indicates that conventional air or steam atomizing provides acceptable methanol atomization.

The combustion performance of alcohol fuels is equal or superior to fuel oils. The levels of CO and UHC are low, smoke formation and aldehydes are not significant, and $NO_x$ emissions and the excess air required for complete combustion are significantly lower than for oil.

The major uncertainty is the impact of methanol firing on the overall boiler efficiency. For the same excess air level and stack temperature, the efficiency based on gross heating value is 8 percent less for methanol than for distillate oil. This is related to the partially oxidized nature of the methanol and would require an additional 8 percent fuel energy input to achieve the same system output. There is also some evidence (ref. 9) that the heat absorbed in the combustion chamber of a scotch marine firetube boiler may be lower for methanol than for distillate; however, this cannot be directly related to overall system heat removal as the convective pass heat transfer was not evaluated. Two factors may provide a compensating effect: (1) the methanol can be fired at a lower excess air level and, therefore, stack losses may be reduced by several percent; and (2) the clean combustion characteristics of methanol may reduce tube deposits, thereby maintaining efficient heat transfer over the long term and reducing cleaning frequency. System efficiencies for methanol, oil, and natural gas are being compared under EPA contract 68-02-1498 for two package boilers; results should clarify the question.

### *Residential Heating*

The two primary fuels for residential heating are distillate oil and natural gas with each fuel accounting for roughly 40 and 60 percent, respectively, of the energy used in existing furnaces in 1972. In recent years, natural gas furnaces have contributed the majority of sales. It should be noted that these furnaces do not have the dual-fuel capability that is found in many commercial systems. There are also completely different furnace configurations used for natural gas than for oil. All of these factors combine to dictate that for residential furnaces, consideration must be given not only to new units designed specifically for methanol, but also to retrofit of existing units designed for distillate oil and natural gas. To fire methanol in a furnace designed for natural gas would require vaporization of the fuel prior to fuel introduction to the burner or other major hardware changes. For retrofit of a natural gas system, methanol is probably not a technically or economically viable alternative; therefore, this paper will discuss only oil. For liquid fuels, it should be possible to develop a furnace capable of firing either methanol or distillate fuel oil with only minor changes (e.g., nozzle).

Since there was no information available on methanol firing in a residential furnace, an experiment was performed in the EPA laboratory. A conventional residential warm-air furnace, designed to fire distillate fuel oil at a nominal 1 gal per hr (1.1 ml per sec), was equipped with a 2.25 gal per hr (2.25 ml per sec) nozzle to maintain an equal energy input firing methanol. When the furnace was started up, ignition was achieved with methanol; however, the flame safety system shut the burner down. Therefore, the burner was removed from the furnace to diagnose the cause. Observation of the methanol flame revealed that it was a translucent orange as opposed to the highly luminous flame produced with distillate oil. Apparently, the cadmium sulfide flame detector, which operates on infrared radiation, does not generate sufficient signal with the methanol flame. In addition, the observations suggest that for methanol firing, a redesign of the burner head may be required to achieve the compact flame required by the residential furnace. Finally, there is some concern that the methanol does not possess the same lubricating properties as fuel oil and a different fuel pump may be required. The net result of these changes would be a replacement burner for methanol firing, probably at a cost of over $100. Based on the other combustion data from methanol firing, it may be projected that emissions of CO and unburned hydrocarbons will be comparable to those from fossil fuels, while $NO_x$ emissions may be lower by as much as 50 percent. Particulate and $SO_x$ emissions *should* be nonexisting.

Another question is the impact of methanol firing on system efficiency. Since the adiabatic flame temperature for methanol is about 220° F (105° C) lower than for fossil fuels, the driving force for heat transfer is lower; however, this may be offset by a longer residence time of the combustion gases in the heat exchanger. The other factor to be considered is the differences in heat losses in the flue gas. These losses are related to the temperature of the flue gas, the mass of flue gas, and to the latent heat in the water vapor. For a given temperature and excess air, methanol has higher sensible and latent heat losses than does distillate oil, due to the greater mass of water generated for an equivalent energy input. This can be observed from some calculations with the **WAFURN** program (refs. 10,11), which can estimate furnace performance as shown in table 1. The difference is largely attributable to increased latent heat loss in the flue gas from methanol. A potential compensating effect should be noted. If the oil is burned at 85 percent excess air to avoid excess smoke formation and the methanol can be fired at 15 percent excess without smoke, the gross efficiencies are essentially equal. This type of change is certainly a strong possibility for retro-

Table 1. Comparison of calculated furnace efficiencies for methanol and distillate oil in a fixed configuration residential furnace

| | Gross efficiency[a] | |
|---|---|---|
| Excess air<br>% | Distillate oil<br>% | Methanol<br>% |
| 15 | 79.9 | 73.9 |
| 50 | 76.1 | 71.0 |
| 85 | 73.3 | 67.8 |

[a] Gross Efficiency =

$$\frac{\text{Heat Delivered To Home in Warm Air}}{\text{Higher Heating Value of Fuel}} \times 100$$

fit to existing oil-fired units; however, the potential is somewhat less for new oil-fired units of modern design that normally operate at 25 to 50 percent excess air.

## CONCLUSIONS

The following conclusions can be drawn:

1. Use of alcohol fuels has the potential for reduced emissions of $NO_x$ and other pollutants.
2. The efficiency of a system utilizing alcohol fuels may be lower than for fossil fuels in the same system; however, the most significant energy loss in the overall scheme appears to be in synthesis of the alcohol fuel from coal.
3. Alcohol fuels can be fired in commercial boilers with a minimum amount of burner modification.
4. Additional combustion technology development is required for the utilization of alcohol fuels in residential furnaces.
5. Fuel supply appears to be the major obstacle in the use of alcohol fuels in area sources. Fuel costs, overall energy efficiency, and environmental aspects should all be factors considered in a decision on alcohol fuels versus other alternatives.

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# ASSESSMENT OF THE APPLICABILITY OF CATALYTIC OXIDATION OF HYDROCARBON AND OTHER FUELS FOR CONTROL OF $NO_x$ AND OTHER POLLUTANTS FROM AREA SOURCES[*]

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*Abstract*

*A review of the state-of-the-art of catalytic combustion concepts has been carried out, and an assessment of the applicability of catalytic combustion to gas and oil-fired home heaters and commercial and industrial boilers has been made. Newly developed high temperature support materials will greatly enhance the field of high temperature catalytic combustion, but current catalyst systems are limited by the catalyst coating to much lower temperatures than the supports. In order to keep combustor temperatures below those that would cause catalyst degradation, as well as to achieve high system efficiency and also to prevent $NO_x$ formation, combustion system concepts such as two stage combustion, flue gas recirculation, and bed heat removal appear necessary. The application of these concepts to home furnaces appears feasible, but the application to larger size units may be more attractive because of their larger initial cost, generally more sophisticated controls, better supervision of equipment, and heat transfer characteristics.*

## INTRODUCTION

More than 150 years ago, Sir Humphry Davy discovered that platinum wires could promote combustion reactions in flammable mixtures, and that the resulting reactions appeared to take place on the surface of the wires, "without flame" and with the high radiative fluxes associated with the solid surface emittance rather than the low emittance of the combustion products (ref. 1). Subsequent study and investigation followed a number of paths reviewed by Spalding in reference 2. Of this work, a substantial fraction which might be termed "fundamental studies of heterogeneous catalysis" has attempted to identify and quantify specific heterogeneous reactions and define the mechanisms by which the solid surface promotes or accelerates oxidation reactions. A second fraction, termed "computational", has dealt largely with mathematical theories and analyses attempting to describe the diffusion of reactants to the promoting surface, the diffusion of products away from it, and the combined heat and mass transfer. A third fraction can be termed "reduction to practice", which includes attempts to construct and employ practical devices exploiting heterogeneous combustion. As is frequently the case in combustion, work in this area has proceeded with very little reference to achievements in fundamentals and computation. Experiments throughout the 1800's demonstrated that various materials promoted heterogeneous combustion reactions to various degrees, and that with increasing surface temperatures the number of materials with the ability to promote reactions increased. The earliest successful practical devices exploited heterogeneous combustion to provide more efficient lamps. The best example is the mantle lantern or Auer light, still sold in great numbers as a "camping lantern", in which combustion takes place on the ash residue of a fiber bag mantle surrounding the fuel/air orifice. This mantle ash contains oxides, including cerium oxide and thorium oxide, which, in addition to constraining radiation emission to desirable lines in the visible spectrum, contribute to the catalytic activity of the mantle (ref. 3).

Concepts close to the original experiments of Davy have been used as passive ignition devices and as combustible detectors, particularly in the form of hydrogen leak detectors. Related applications along this line include catalytic fume abatement devices and automotive catalytic converters, both depending on precious metals to oxidize low concentrations of combustibles in gas streams.

After extensive practical experimentation, Bone publicized various high-temperature applications of

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surface combustion, using for the most part conventional ceramic materials (refs. 4,5). He built and tested surface combustion furnaces, boilers, and permeable panels. This line of investigation has not, however, proven very fruitful due to the complexity and expense of the required equipment and the limited industrial need for high radiative fluxes, although some commercial equipment of this type is available (ref. 6).

The range of commercial devices has recently led to some specialization of terminology in a field where formerly several terms were used interchangeably. The term "radiant burner" refers to burner types employing a refractory surface situated within or near the flame so as to provide for radiant heat transfer from the flame area. Heterogeneous combustion occurs in these devices to some degree, but generally does not dominate the process and homogeneous combustion constitutes most of the reaction mechanism. "Surface combustors" employ refractory in a similar manner but use special provisions of air/fuel distribution to maximize the amount of heterogeneous combustion occurring. "Catalytic combustors" employ special additives (usually precious metals) to enhance the heterogeneous activity of the surface.

There are several reasons for the recent upsurge of interest in catalytic combustion. Use of the diffusion flame for combustion places a limit on the lower level of control that can be achieved economically for clean fuels (approximately 25 to 30 ppm of $NO_x$ for small sources), and catalytic combustion appears to be able to reach lower levels of $NO_x$ control (perhaps < 10 ppm). In addition, in order to minimize the combustion system heat loss in the exhaust, it is necessary to minimize the exhaust mass, which implies running at stoichiometric conditions. To minimize $NO_x$ production and also maximize overall system efficiency, systems such as two-stage combustion, flue gas recirculation, or cooling of the catalyst bed must be examined.

The use of catalytic combustors in gas turbines because of their high excess air requirement is also of interest. The Aerospace Corporation, under an EPA contract, reviewed the state-of-the-art of surface and catalytic combustion concepts in 1973, and assessed the applicability of these concepts to large utility boilers and stationary gas turbines (ref. 17). It was concluded that catalytic combustors might be applicable to both existing and new stationary gas turbines, but it was unlikely that catalytic combustors could be economically installed in utility boilers.

Finally, there is a continuing interest in producing a compact "high-performance", low-emission combustor, and catalytic combustion is a candidate for this system.

This study, then was undertaken to assess the present state-of-the-art in catalysis and catalytic combustion, to assess the feasibility of catalytic combustion for the control of $NO_x$ emissions from stationary sources not covered by the Aerospace study, and to define problems that might be encountered in the redesign and/or retrofit of catalytic combustors for stationary sources.

## AVAILABLE CATALYST MATERIALS

The materials needed for a catalytic combustion system are those associated with the support, the washcoat, and the catalyst itself. The importance of each of these elements in the system is described below.

### *Support Materials*

The catalytic support serves two important functions in a catalyst system:

- It increases surface area of the active metal or metal oxide by providing a matrix that stabilizes the formation of very small particles.
- It increases thermal stability of these very small particles, thus preventing agglomeration and sintering with consequent loss of active surface.

Most common support materials are $Al_2O_3$ and $SiO_2$. The application of these supports in catalytic combustion presents several significant problems that must be considered.

- The large space velocities used in a catalytic combustion unit will result in severe pressure drops if the catalyst beds are packed with conventional pellets like those used in the petroleum industry.
- The high reaction rates of complete combustion usually present severe pore diffusion limitations for the effective operation of the system.
- The high temperatures and heat fluxes place special constraints on the thermal properties of the system.

Over the last decade, a number of new materials and new preparative techniques have been developed to overcome these problems. These materials have emphasized the use of monolithic support structures and surface impregnated pellets.

Monolithic supports are composed of small parallel channels of a variety of shapes and diameters. These structures may be in the form of honeycombed ceramics extruded in one piece, oxidized aluminum alloys in rigid cellular configurations, or multilayered ceramic corrugations. The channels in honeycomb-like structures have tubular diameters of 1 to 3 mm. The overall diameter of the monolithic support may vary from 2 cm to 60 cm, and is limited, in the case of extrusion processes, by availability and operation of the metal die. Materials of fabrication are usually low surface area ceramics such as mullite ($3Al_2O_3 \cdot 2SiO_2$) or cordierite ($2MgO \cdot 5SiO_2 \cdot 2Al_2O_3$). The refractory monolith is produced with macropores (1μ – 10μ) and may be coated with thin layers of catalytic materials, 5- to 20-weight percent coatings being common.

The two major advantages of monolith supports for catalytic operations are the high superficial or geometrical surface area and the low pressure drop during operation. Table 1 lists the currently available monolith materials, and figure 1 shows typical extruded monolith structures.

In addition to the monoliths, highly porous pelleted materials can also be used as the catalyst support. Pellets come in a wide variety of materials, shapes, and sizes, but have the disadvantage of a higher pressure drop through the bed.

### *Wash Coat Materials*

The low surface area of the monolith structure requires the application of a thin coat of oxide such as $Al_2O_3$. This wash coat, which strongly adheres to the ceramic or refractory support, provides a uniform high surface area while still insuring that the catalytic material which is subsequently impregnated on the wash coat is close to the main flow of reactants. The thickness of the wash coat is usually between $10 \times 10^{-6}$ and $20 \times 10^{-6}$ m (10-20 microns).

Many different materials can be used as wash coats. $ZrO_2$, for example, has been used in test runs for the catalytic combustion of hydrocarbons in automotive

Table 1. Available monolith supports

| Manufacturer | Product | Description | Temperature limit (°F) |
|---|---|---|---|
| American Lava Corporation | Thermacomb AlSiMag 614 | Dense 96 percent Alpha-alumina | 2,800 |
| | Thermacomb AlSiMag 776 | Porous 96 percent Alpha-alumina | 2,192 |
| | Thermacomb AlSiMag 795 | Cordierite | 2,192 |
| Corning Glass Works | Celcor 9475(EX-20) | Cordierite | 2,200 |
| E. I. du Pont de Nemours & Company | TORVEX | Alumina | 2,732 |
| | | Mullite | 2,462 |
| General Refractories Company | Versagrid | Cordierite | 2,550 |
| | | Mullite | 3,000 |
| Norton Company | | Silicon Carbide RX387 | 3,000 |
| | SPECTRAMIC Honeycomb | Silicon Nitride RX384 | 2,800 |
| | | Silicon Oxynitride RX385 | 2,800 |

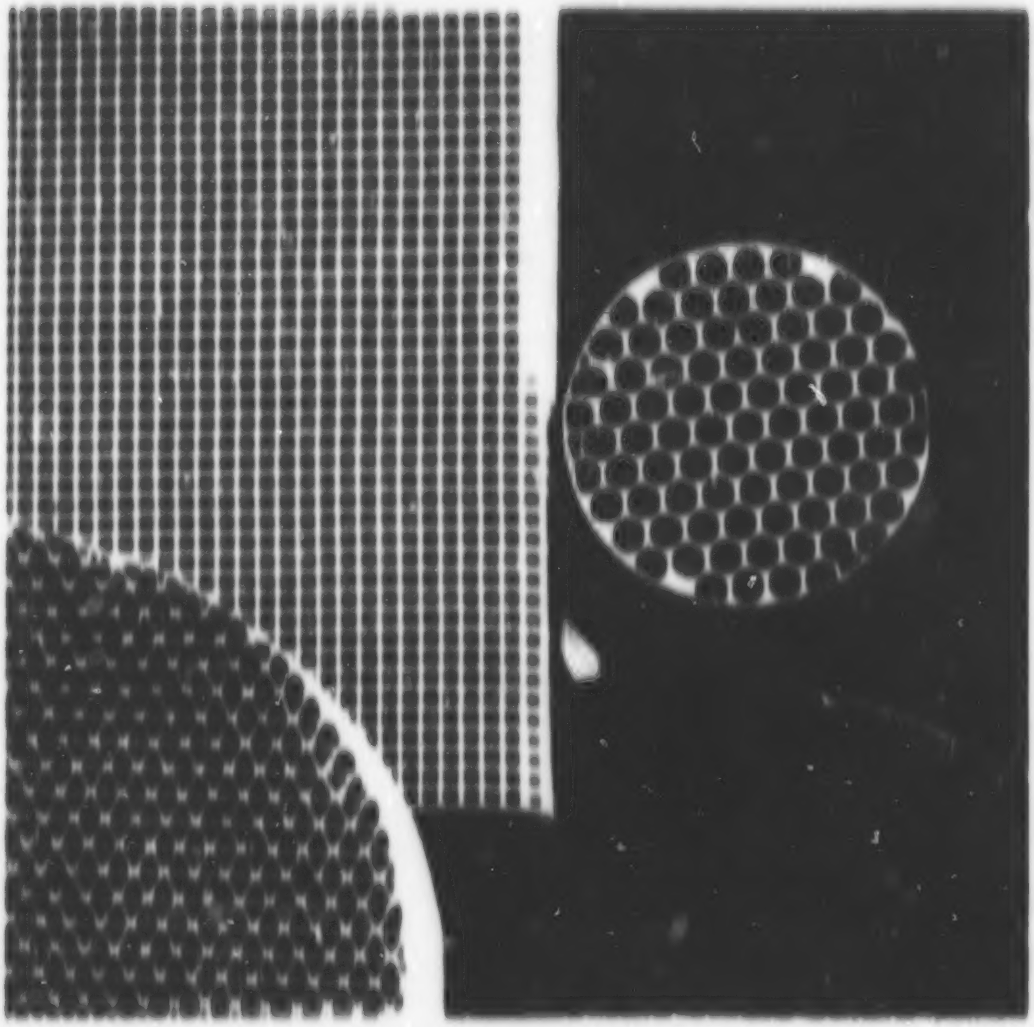

Figure 1. Typical extruded monolith structures (courtesy of General Refractories Company).

exhaust. Variation in the type of wash coat can have important consequences in the stability and life of the catalyst system.

*Catalyst Coatings*

Although the field of catalysis has progressed substantially over the past decade, its theoretical aspects are not yet at the degree of sophistication which would enable one, a priori, to choose or design an active oxidation catalyst with a given set of catalytic properties. However, a vast amount of data exists which permits the development of correlations useful for choosing promising candidates based on excellent catalytic activity and catalyst stability. Over the last decade there has been a rapid development of the art, science, and technology necessary to synthesize, test, and manufacture ultrastable oxidation catalysts for the abatement of automotive emissions. These catalysts operate under the most stringent conditions, and sometimes at temperatures close to 2,000° F. The expertise developed in this area will be useful in the development of a stable catalytic combustion system.

Two broad classes of catalytic coating materials are available: metals and oxides. The metals of catalytic interest are listed in table 2. Of these metals, the only ones which have a possibility of remaining in the metallic state in a high-temperature, oxidizing environment are the noble metals; the others readily form oxides. Of the noble metals, a large volume of data and correlations are available for platinum and palladium because of their use as automotive oxidation catalysts. They are among the most active catalysts for the oxidation of a number of fuels, including methane, methanol, and hydrogen. The high activity of these metals is related to their ability to activate $H_2$, $O_2$, and carbon-hydrogen and oxygen-hydrogen bonds. Palladium and platinum are readily prepared in a highly dispersed form on a number of support materials. Because of the high activity of these metals per unit area of metal surface (specific activity) and the ability to attain high dispersions, only small amounts are necessary for catalytic combustion (0.1 to 0.5 weight percent). Ruthenium metal is another possible candidate for catalytic combustion; however, under oxidizing conditions it forms a volatile oxide ($RuO_4$), which is rapidly removed from conventional catalyst supports. One approach to solve this problem has been to anchor Ru to a support by forming a relatively stable perovskite structure with certain oxides such as $La_2O_3$. Osmium is even more volatile and poisonous than ruthenium in an oxidizing environment. Also, as with iridium and rhodium, it is very costly, and available in limited supply. The use of the latter two metals, if at all, would be restricted to small quantities in multimetallic systems. Silver, while quite active at low temperatures for the activation of $O_2$, melts at low temperatures and therefore sinters to a significant degree at the high temperatures of catalytic combustion. However, it could find use as an additive in a multimetallic catalyst. Gold is very inactive for oxidation, and would therefore only be considered as a structural or electronic modifier for multimetallic catalysts.

**Table 2. Metals of interest for catalytic combustion**

| Group VIII[a] | | | Group IB[a] |
|---|---|---|---|
| Fe | Co | Ni | Cu |
| Ru | Rh | Pd | Ag |
| Os | Ir | Pt | Au |

[a] Enclosed metals are considered noble.

Based on the above considerations, those metals which show the greatest promise for use in a single-active-element catalyst system are platinum, palladium, and ruthenium (stabilized). Highly active and stable catalyst systems can be produced through the use of multimetallic systems (such as palladium/platinum), as well.

The catalytic properties of metal oxides have been investigated by a number of researchers, including research in catalytic oxidation. As for metals, it has been found that the activity for hydrocarbon oxidation parallels the ability to catalyze the homomolecular exchange of oxygen. It has also been noted that the oxides of transition metals containing ions with partially filled d orbitals have the greatest activity. Based on these considerations, the most active simple oxides are $Co_3O_4$, $MnO_2$, NiO, CuO, $Cr_2O_3$, $Fe_2O_3$, and $V_2O_5$. Multicomponent metal oxides of interest include stable spinel structures such as $Co_3O_4/CuO$, $Cr_2O_3/CuO$, and $La_2O/Co_3O_4$.

*Temperature Capability of Catalyst/Support System*

The choice of an optimum catalyst/support combination requires a consideration of the temperature capability of a given combination. The low-temperature limit is dictated by the so-called "light-off" temperature. Solutions to this problem are not complex for most catalytic combustion systems, since noble metal catalysts exhibit good light-off characteristics for most fuels of interest. The major thermal limitation for catalytic combustion is the high temperature of operation. The phenomena which lead to catalyst deactivation at high temperatures are

1. sintering of the catalytic species,
2. changes in catalyst stoichiometry,
3. sintering of the wash coat,
4. thermal degradation of the ceramic support material, and
5. mechanical failures.

Sintering of the catalytic species will lead to a concomitant loss in surface area and therefore a loss in catalyst activity per unit mass of catalyst. The temperature at which sintering occurs is a function of the catalytic material. In an oversimplified manner this sintering or crystallite growth is a function of the melting point for metals. A number of techniques have been developed to minimize or prevent sintering. For example, multimetallic systems can be prepared which are more stable than the constituent metals. A number of structural promoters are also known.

Stoichiometry changes for oxides can lead to a catalyst with dramatically different catalytic properties. Loss of lattice oxygen can cause an increase in the energy required to activate $O_2$ and thereby decrease combustion activity. One method for overcoming this problem is to dope the lattice with a material which causes a decrease in the energy necessary to activate oxygen and also stabilizes the stoichiometry of the lattice.

A third mechanism of thermal deactivation is washcoat sintering. At temperatures above 1,800° F high surface area $\eta$ or $\gamma$ $Al_2O_3$ undergoes a phase change to $\alpha$ $Al_2O_3$ with concomitant sintering. The change may be from a surface area of 300 $m^2/g$ to about 5 $m^2/g$. This sintering results in pore closure and a "burying" of active catalytic sites in the $Al_2O_3$. To minimize this problem, it is possible to work with catalysts for which the catalytic phase has been deposited on a presintered $Al_2O_3$. Alternatively, other materials which are thermally more resistant may be investigated as washcoats. These might include $ZrO_2$, $ThO_2$, and $UO_2$.

At very high temperatures, the ceramic support, be it spheres or monolithic honeycomb structures, begins to degrade. Typical monolith fail temperatures have been given in table 1. Although catalytic combustion units are not expected to operate continuously at the temperatures listed, the possibility of local hot spots occurring due to uneven air/fuel mixing and local catalyst bed nonuniformities must be considered.

Thermal expansion and contraction may also occur at high temperatures. Both pellet and monolithic supports have thermal expansion coefficients different than their mounting hardware. Considerable catalyst mechanical attrition can occur if the catalyst becomes loose, thus causing a decrease in catalytic performance.

## EXISTING APPLICATIONS OF CATALYTIC OXIDATION CONCEPTS

The existing application of catalytic oxidation concepts in industry are largely in the low temperature area at this time. The primary applications of catalytic combustion are in nitric acid plant tail gas cleanup, industrial odor control, small catalytic heaters, and automotive oxidation catalyst systems.

### *Nitric Acid Plant Tail Gas Cleanup*

Nitric acid is produced commercially by reacting ammonia with air to produce nitrogen oxides, which are then absorbed in water to yield nitric acid. Large amounts of unabsorbed nitrogen oxides in the tail gas from the absorption tower pose a pollution problem, which has been solved in some cases by the catalytic processing of this tail gas over platinum group metals to yield useful energy in the form of steam and/or power. The basic reactions for the catalytic treatment of nitric acid tail gas over platinum, palladium, or rhodium for methane reducing fuel are:

1. $CH_4 + 4NO_2 \rightarrow 4NO + CO_2 + 2H_2O$ (decolorization),
2. $CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O$ (combustion), and
3. $CH_4 + 4NO \rightarrow CO_2 + 2H_2O + 2N_2$ (abatement).

The tail gas reactor outlet temperature is usually between 1,250° F and 1,300° F. Support materials for the catalyst have included nichrome wire, alumina pellets, and alumina honeycomb materials.

### *Industrial Odor Control*

The elimination of organic fumes is desirable from both air pollution and fire safety points of view. The platinum metals have been used for several years as catalysts for the oxidation of carbon monoxide and a wide range of organic molecules in the presence of air or oxygen. Most odors are caused by the emission of low concentrations of organic molecules to the air, with these organic molecules always containing carbon, and hydrogen and generally sulphur, nitrogen, and oxygen as well. Since most industrial odor problems are caused by organic compound concentrations well below the level required for spontaneous combustion in air, it is necessary to raise the contaminated air stream temperature to a level at which combustion can occur. The use of catalysts lowers the temperature needed to achieve odor removal, and also lowers the necessary residence time at the combustion temperature.

### *Low Temperature Catalytic Heaters*

Low temperature catalytic heaters are characterized by the small portable radiant heaters that operate at temperatures below 800° F. Operating characteristics include heat release rates of approximately 75 Btu/in.$^2$ and lifetimes of several thousand hours. Gaseous fuel is distributed in a uniform fashion to all parts of a catalytic pad, and combustion takes place on the surface of the fibers of the pad.

The Control Systems Laboratory of the EPA has conducted an extensive emissions testing program on a number of catalytic heaters, as reported in reference 7. No correlation between emissions and specific heat release rates was found, and CO and UHC levels were generally quite high.

### *Automotive Exhaust Catalysts*

Since platinum metal catalysts were selected for emission control on conventional automotive internal combustion engines for the 1975 model year, a great deal of development work went into these emission control systems. In general, $NO_x$ emissions are controlled by a reduction mechanism, and CO and UHC emissions are removed by catalytic oxidation with secondary air added to the exhaust steam to insure complete oxidation.

A reactor for catalytic exhaust emission control has three essential design features:

1. A ceramic support on which the catalyst is deposited in a manner that prevents attrition,
2. Rapid warmup of the catalyst unit, and hence rapid light-off, and
3. Nearly complete conversion efficiency.

The essential features of a satisfactory CO/UHC oxidation catalyst for automotive emission control are (ref. 9):

1. A light-off temperature in the region of 250° C,
2. Conversion efficiencies in excess of 90 percent for both CO and UHC at space velocities up to 150,000/hr,
3. High temperature stability of the support and platinic crystallite system at temperatures to 950° C, and
4. Poison resistance to compounds containing lead, phosphorus, and sulfur.

Platinum-palladium catalysts have been extensively tested in full-scale vehicle tests (ref. 9). The differences between platinum and palladium catalyst performance were quite small.

Reference 10 discusses possible substitute catalysts for platinum in automobile emission control. In this study, it was concluded that base metal catalysts generally are not as effective as platinum/palladium catalysts for automobile emission control, especially for hydrocarbon and carbon monoxide oxidation. For $NO_x$ reduction, certain base metal catalysts initially are more active and selective than are noble metal catalysts; however, most suffer from rapid deactivation.

## CURRENT RESEARCH PROGRAMS IN CATALYTIC COMBUSTION

Since catalytic combustors have excellent potential for low $NO_x$ emissions, a number of research programs investigating their use in automotive, gas turbine, and domestic appliance applications are currently going on.

### *Gas Turbine Catalytic Combustor Research*

Because the gas turbine operates under high (approximately 200 percent) excess air conditions, thereby holding combustion temperature down, it has excellent potential for catalytic combustion applications. Current or recent research programs in this area include those conducted by the Air Force Aero Propulsion Laboratory (ref. 11), NASA Lewis Research Center (ref. 12), Detroit Diesel Allison Division, General Motors Corporation (ref. 13), and Engelhard Industries. In all of the studies reported to date, no information has been made public concerning the catalyst system, thereby severely limiting the usefulness of the research. However, the present operating conditions have been reported to be:

1. Inlet temperature: 400-1,000° F,
2. Operating temperature: 2,000-2,600° F,
3. Pressure: 1-10 atm,
4. Heat release rate: 100,000-20,000,000 Btu/hr ft$^3$ atm,
5. Combustion efficiency: 99.99 percent, and
6. $NO_x$ emissions: 1 ppm.

### *Automotive Application Research*

The Jet Propulsion Laboratory has been conducting tests on a compact onboard hydrogen generator for use with a hydrogen-enriched gasoline internal combustion engine. This modified fuel system, called partial hydrogen injection, substantially lowers $NO_x$ emissions and also increases engine efficiency considerably. It was found that a nickel oxide catalyst speeds up the partial oxidation reaction, and nickel oxide coated alumina pellets have been used as the catalyst system. Typical operating conditions for this system are:

1. inlet temperature: 450° F,
2. catalyst temperature: 1,774° F,
3. pressure: 1 atm.

Further information on the JPL system is given in references 14 and 15.

### *Domestic Appliance Catalytic Combustion Research*

The Institute of Gas Technology is currently conducting catalytic combustion research on smokeless home appliances using reformed natural gas (nominally 80 percent hydrogen and 20 percent carbon dioxide) as fuel, and on range top burners using hydrogen as fuel. The reformed natural gas catalytic combustion burners used a noble metal catalyst placed on a permeable support plate, and are self igniting at room temperature (ref. 16).

## PRELIMINARY DESIGN CONCEPTS

Based upon the current catalyst materials, existing industrial uses, and current research programs, preliminary conceptual designs for the application of catalytic combustion to residential space heaters and commercial and industrial boilers have been made. The conceptual designs presented are by no means optimum, since very little data exist on which to design a catalytic combustor, but rather represent possible choices for catalytic combustion that appear promising but which are not currently being done.

*Home Heater Retrofit*

Nearly all existing gas-fired burners consist of the naturally aspirated "stick" or "log" type burner, for either warm air or hot water application. These burners are generally of the premixed type and rely on ample quantities of secondary excess air to keep the "combustion chamber" cool. In reality, there usually is no combustion chamber as such; firing is directly to the heat exchange surface.

Figures 2 and 3 show two possible replacements for the conventional log burners. In the first case (fig. 2) heat is transferred from a monolithic bed by radiation only. Preliminary calculations show that heat transfer rates are sufficient to keep the bed below 2,200° F without exceeding a maximum metal temperature of 900° F. A summary of the calculations for figure 1 is given in table 3.

Figure 3 presents a catalytic bed combustor for retrofit application to a gas-fired furnace utilizing small U-tubes of cooling water. The heat absorbed by the cooling water is then transferred to the circulating air just prior to entering the furnace. This arrangement requires an auxiliary pump and finned tube heat exchanger. The water cooling circuit is arranged to come on after the catalytic bed has reached a specified temperature. Depending on the length of time required for the water

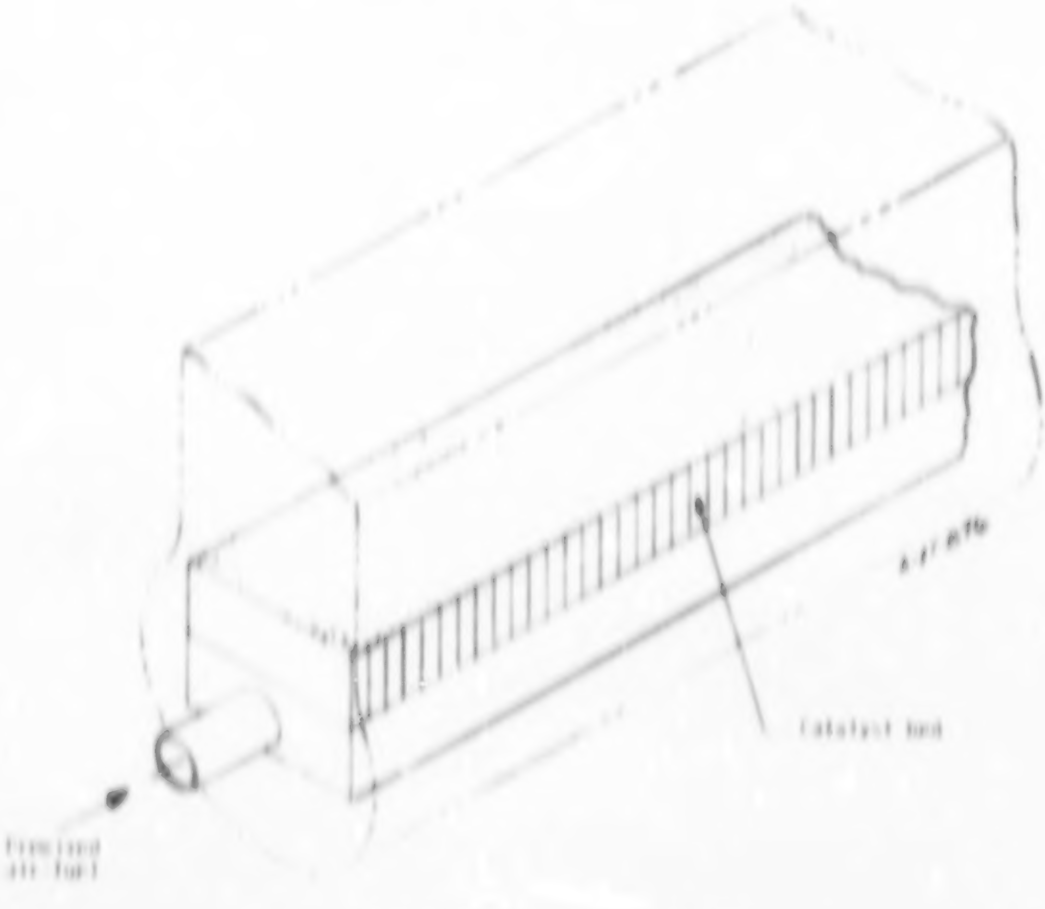

Figure 2. Home heater retrofit design #1.

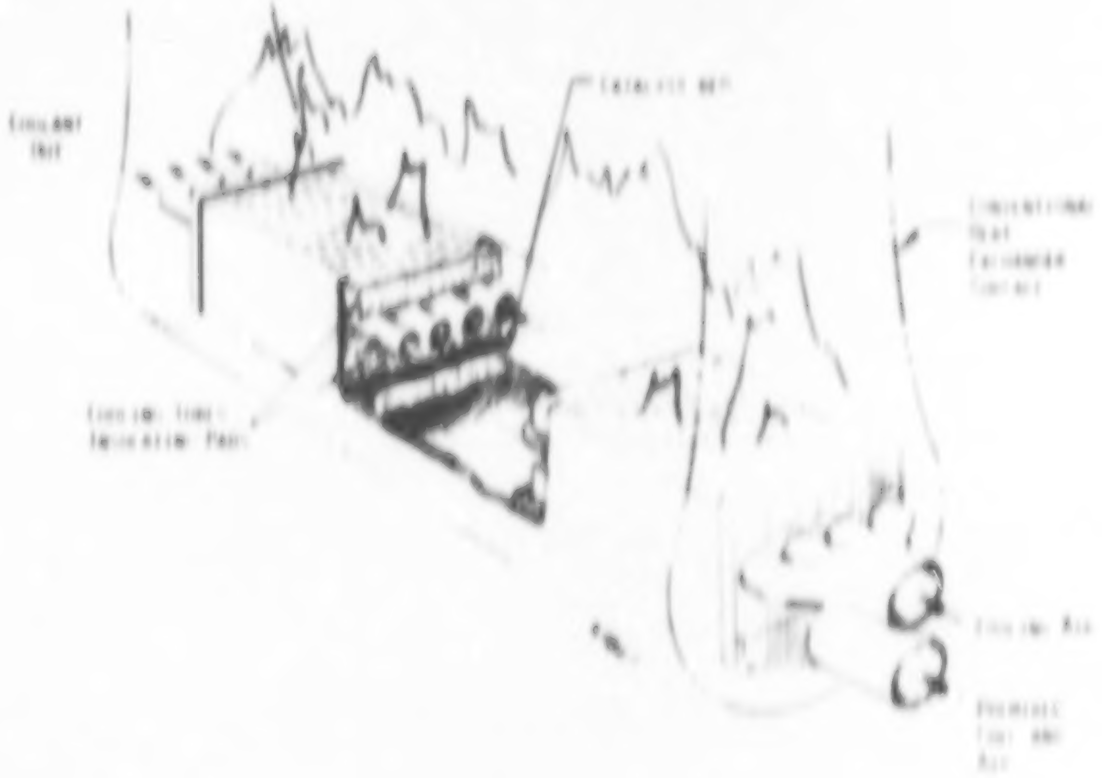

Figure 3. Home heater retrofit design #2.

system to heat, it may be necessary that the circulating air fan come on sooner than current practice to insure that heat is extracted from the water and boiling does not occur. Further design data are given in table 4.

The two home heater retrofit designs just presented could be applied to oil combustion by adding an air preheater and oil vaporizer. In the case of an oil fired furnace, however, new design appears more feasible than retrofit.

*Home Heaters – New Designs*

The freedom of a completely new design presents fewer constraints on physical size and heat transfer arrangement. There will still be an overall size limit (similar to current practice) but this is easily achieved. Two other basic criteria which will not be as easy to meet are cost and noise, the latter because of the higher pressure fans that may be required to achieve higher heat transfer rates. Within these limits a great variety of gas and oil fired warm air and hot water heating systems can be considered. For oil fired units the requirements of preheated combustion air and vaporized oil still exist. For either fuel it is necessary to take into consideration either cyclic operation or modulation to match the variation in load. Coupled with these aspects is the transient response of the furnace. Following are descriptions of three designs which warrant further study.

The first design, pictured in figure 4, involves radial staging of the catalyst bed, lean catalytic first stage, addition of fuel before the second stage, and catalytic combustion of the second stage. The unit is compact, involving a concentric cylinder arrangement of the catalyst bed, fuel addition units, and outer shell. The outer shell can either be water or air cooled, with additional fins placed in the outer shell if it were air cooled. The catalyst bed could either be a packed bed, a fiber mat, or a monolith bed. Fuels for this application would most likely be the gaseous fuels, but a prevaporized oil could also be used. Thermal or electrical startup similar to the retrofit design would be required for oil to

Table 3. Data on home heater retrofit design # 1

Length: 15 inches
Width: 2 inches
Height: 0.5 inch
Volume: 15 $in^3$
Surface area per unit volume: 50 $ft^2/ft^3$
Height required to be coated with catalyst: 0.25 inch
Heat release in bed: 25,000 Btu/hr
Heat transferred by radiation: 11,400 Btu/hr
Heat transfer coefficient on air side: 8.9 Btu/hr-$ft^2$-°F
Pressure drop through bed: < 0.25 in. $H_2O$
Bed temperature: 2,200° F
Wall temperature: 900° F
Bed type: Honeycomb monolith
Number of units: 4

Table 4. Data on home heater retrofit design # 2

Width: 2 inches
Length: 15 inches
Height: 1.0 inch
Heat release per burner: 25,000 Btu/hr
Total number of burners: 4
Number of cooling U-tubes: 6
OD of cooling tubes: 1/16 inch
Heat transferred from bed by radiation: 4,612 Btu/hr
Heat absorbed by tubes: 6,700 Btu/hr
Coolant flow rate per burner: 21.5 gal/hr
Exit gas temperature: 2,200° F
Coolant inlet temperature: 70° F
Coolant exit temperature: 120° F
Pressure drop through cooling tubes: 11.16 ft $H_2O$

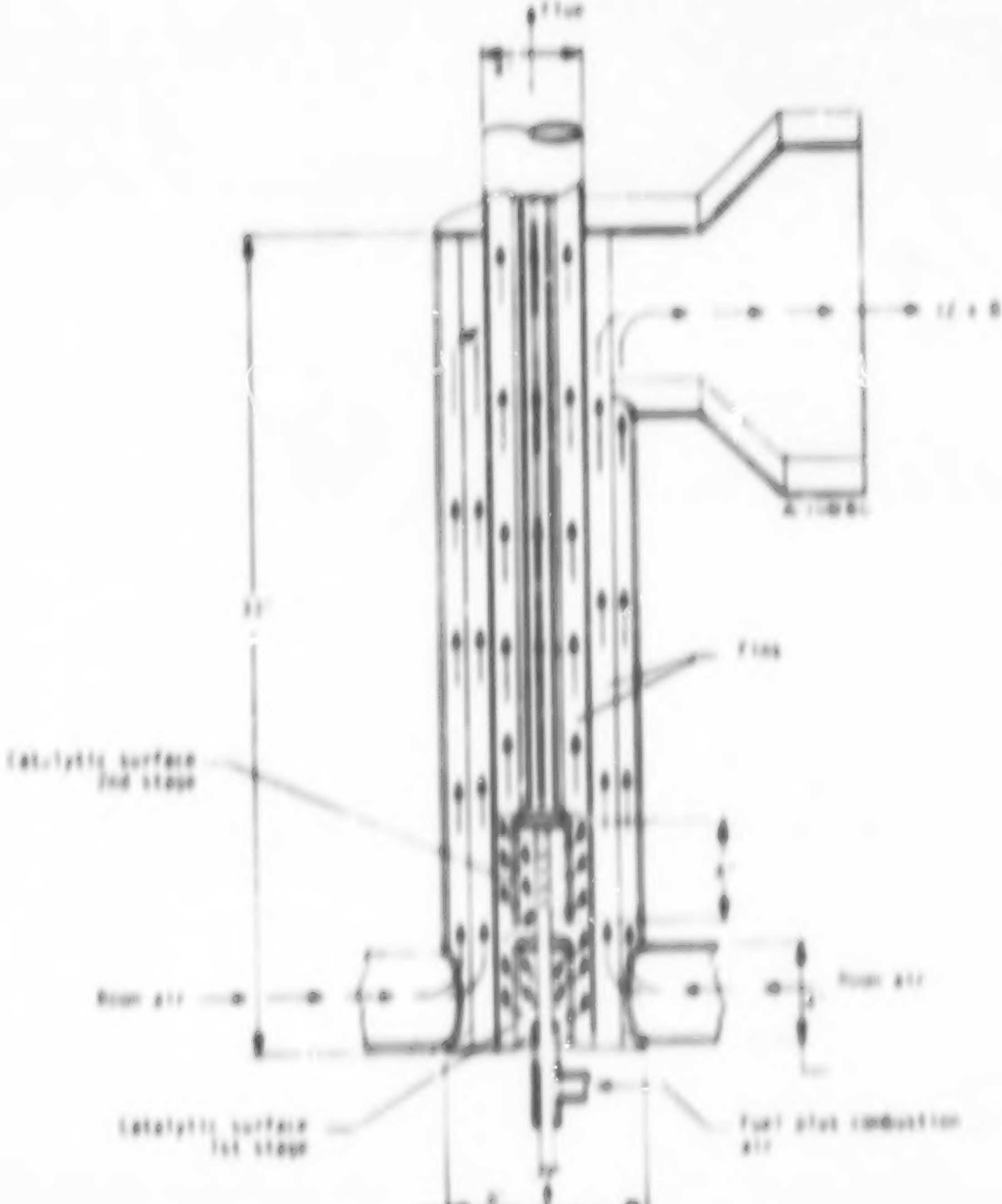
Flue
12 x 8
Fins
Catalytic surface
2nd stage
Room air
Room air
Catalytic surface
1st stage
Fuel plus combustion
air
Additional fuel

Figure 6. Home heater design #1.

vaporize the fuel and preheat the combustion air. Oil vaporizing tubes would be placed between the cold shell and the catalytic surface. Table 5 summarizes the important design parameters. Note that the overall dimensions are well within current practices, although the room air fan, combustion blower, and fuel controls must be packaged into the unit as well.

It must also be noted that sufficient heat must be extracted from the first stage to achieve two goals:

1. To insure the maximum flame temperature in the second stage does not exceed 2,800° F - 3,000° F, to achieve low $NO_x$, and be within the limits of the catalyst.
2. To lower the temperature sufficiently to prevent thermal combustion prior to the second stage catalyst bed after introduction of the second stage fuel.

The latter criterion can be circumvented if the velocities are greater than the flame speed. This can be achieved by appropriately sizing the passages.

The second design, shown in figure 5, uses a conical fibrous catalyst surface to radiate to an outer air or water cooled shell. A premixed mixture of air and fuel would be injected behind the fibrous pad and ignited at the outer surface. After exchanging heat radiatively with the outer shell the flue gases are passed through in a multipass crossflow arrangement outside the tubes. This design is a single stage, operating with minimum excess air but relying on radiation cooling to keep the catalyst surface cool. It could be designed to operate on oil.

Figure 6 shows a concept utilizing heat pipes between sections of catalysts. The heat is picked up by the room air stream flowing adjacent to either side of the combustion chamber. This design could easily use oil or gaseous fuel. The first combustion chamber would be modified to utilize a startup oil spray nozzle firing initially and later switched to vaporized oil. The oil vaporization tubes could also be located between catalyst beds. The remaining heat is finally extracted through a convection section at the right hand side of the figure.

Table 5. Data summary, home heater design # 1, 100,000 Btu/hr

| | 1st Stage | 2nd Stage |
|---|---|---|
| Heat release (Btu/hr) | 68,750 | 31,250 |
| Stoichiometry | 1.60 | 1.10 |
| Gas inlet temperature (°F) | 80 | 1601 |
| Gas exit temperature (°F) | 2200 | 2591 |
| Catalytic surface requirement ($ft^2$) | 6.17 | 2.78 |
| Surface area/unit volume ($ft^2/ft^3$) | 200 | 200 |
| OD (inches) | 2.96 | 2.43 |
| ID (inches) | 2.00 | 2.00 |
| L (inches) | 4 | 4 |
| Pressure drop (inches $H_2O$) | < 0.04 | < 0.1 |

Heat transfer area downstream: 17.26 $ft^2$

Average overall U = 3 Btu/hr-$ft^2$-°F

Exit gas temperature: 600° F

Use 20 fins 1.3 inches long on either side

Cooling air flowrate: 1,000 scfm

Pressure drop air side: 0.122 in. $H_2O$

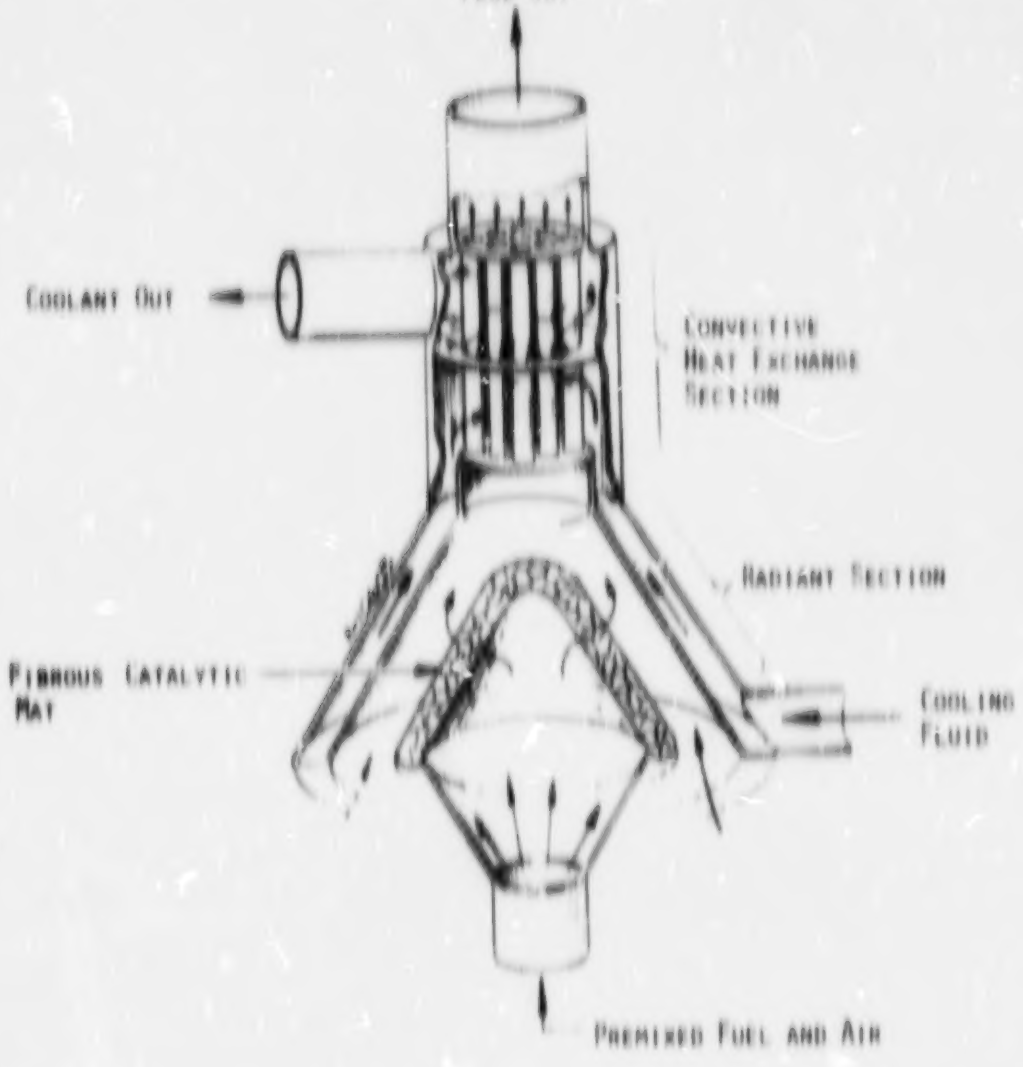
FLUE OUT
COOLANT OUT
CONVECTIVE HEAT EXCHANGE SECTION
RADIANT SECTION
FIBROUS CATALYTIC MAT
COOLING FLUID
PREMIXED FUEL AND AIR

Figure 5. Home heater design #2.

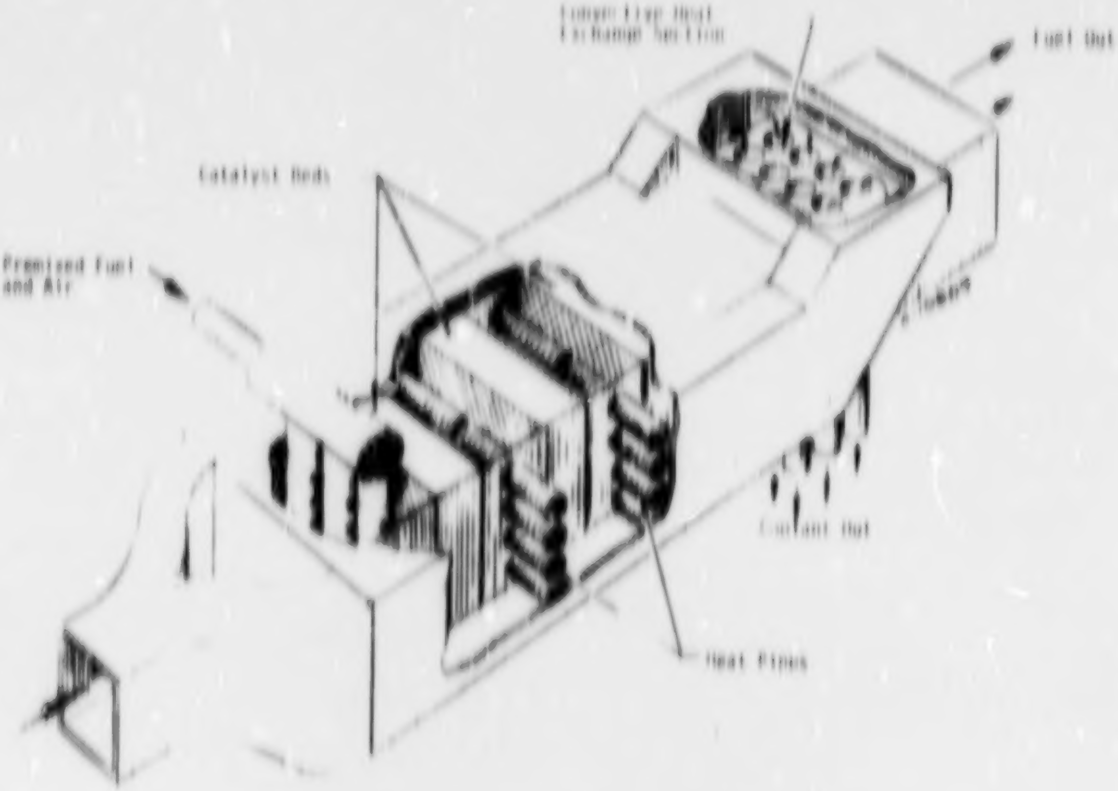

Figure 6. Home heater design #4.

*Commercial and Industrial Boiler Designs*

The principal existing commercial boiler styles in use are the cast iron and firetube designs. Within the firetube design, packaged scotch and firebox are prevalent. All of these designs have relatively large initial combustion volumes, whether gas or oil fired. The firebox designs, including some of the cast iron boilers, employ a refractory or refractory felt-lined combustion chamber. The others (packaged scotch) utilize a large water backed volume for the initial combustion chamber. The on-off cycles are highly dependent on the individual load.

The principal design difficulty is to extract sufficient heat from the bed to achieve low $NO_x$. All the problems associated with oil-fired home heater applications also apply, but the most significant difference is that the capital cost of these units is an order of magnitude higher than the home heating systems. This allows considerably more latitude in potential designs.

Figure 7 shows a potential new design concept for a firetube boiler. The firetubes are filled with catalytically impregnated pellets. A combustion chamber is added of any desired length for first-stage thermal combustion, if required. In addition, a second-stage can be added as desired, followed by additional cooling. Flue gas recirculation can be added to this design as well, and it also applies to the small industrial boiler.

A catalytic water wall design is shown in figure 8. Actually, this is very similar to the Home Heater Design #1 (fig. 4) in that it employs a cylindrical catalytic combustor radiating to the water wall. This radiant section is followed by a convective section. This design is a single stage and relies on the high radiant cooling.

## SUMMARY

Based on a review of the state of the art of catalytic combustion concepts, an assessment has been made of their applicability to gas- and oil-fired home heaters and

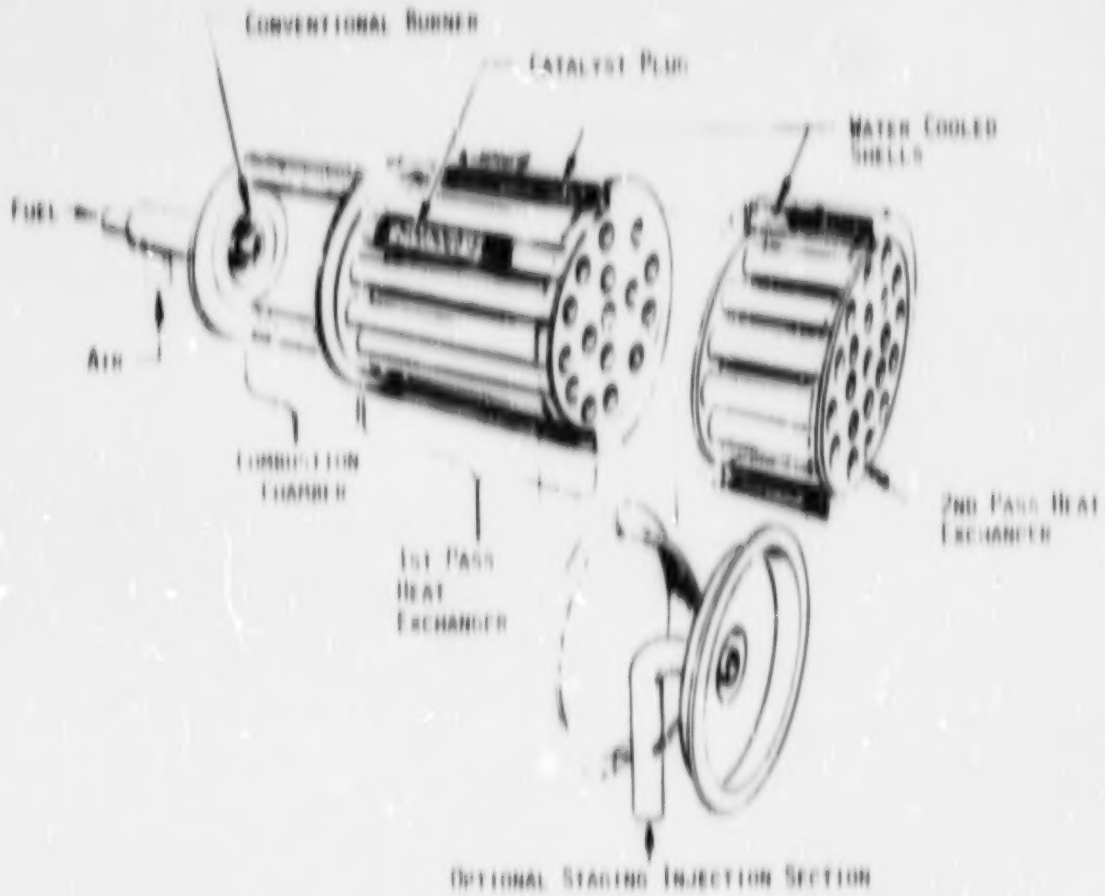
CONVENTIONAL BURNER
CATALYST PLUG
WATER COOLED SHELLS
FUEL
AIR
COMBUSTION CHAMBER
1ST PASS HEAT EXCHANGER
2ND PASS HEAT EXCHANGER
OPTIONAL STAGING INJECTION SECTION

Figure 7. Commercial and industrial boiler design # 1, firetube boiler.

commercial and industrial boilers. Preliminary conceptual designs have been made, but these designs are limited due to the basic lack of knowledge of the catalyst characteristics, wash coat, support, and bed depth required for an oxidation reaction to go to completion.

Because of the need for high system efficiency (to conserve fuel) and low operating temperature (< 2,800° F to prevent $NO_x$ formation), the system concepts of flue gas recirculation, two-stage combustion, or direct bed heat removal must be examined along with the catalytic combustion process to achieve the desired goal. There appear to be no major technical obstacles to producing a catalytic combustion space heater or boiler at this time.

Because of formidable problems associated with oil-fired equipment, including oil vaporization, startup, and air preheating, catalytic retrofit of oil-fired units is not recommended. In fact, retrofit for gas-fired systems also exhibits special problems, such as limited furnace volume, low heat transfer coefficient, and cyclic nature of operation, and therefore redesign represents the more viable solution for catalytic combustion applications.

The basic lack of information concerning the catalyst bed is a significant hindrance to the designer, and a program aimed at obtaining this basic design data through catalyst screening tests and small-scale system concept evaluation tests is strongly recommended.

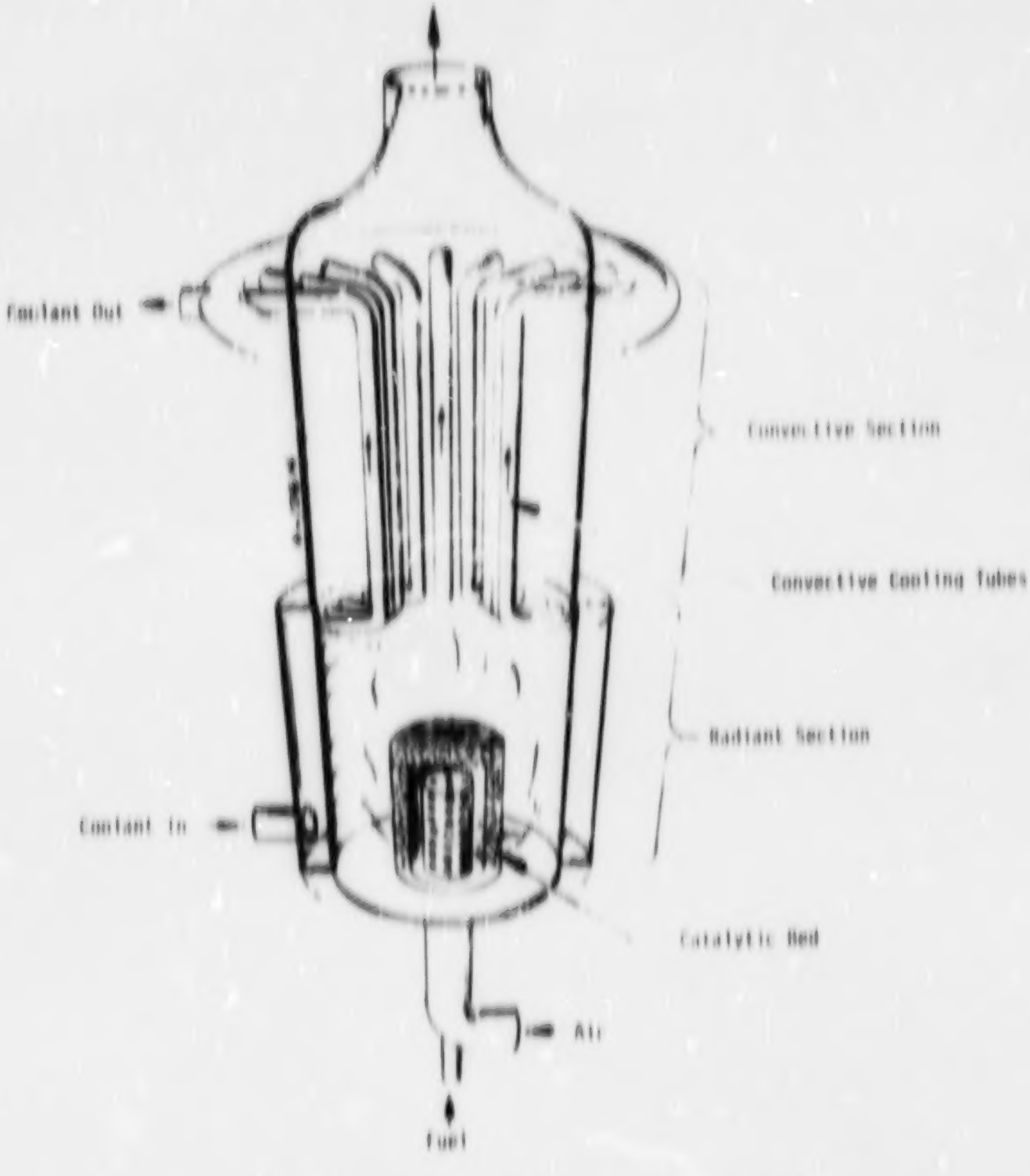
Coolant Out
Convective Section
Convective Cooling Tubes
Radiant Section
Coolant In
Catalytic Bed
Air
Fuel

Figure 8. Commercial and industrial boiler design # 2, water wall configuration.

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# HEAT PIPE APPLIANCES

James F. Rice[*] and Edward F. Searight[†]

*Abstract*

*Recent awareness of the extent of energy shortages in this country has increased the recognition of the necessity of designing appliances which are capable of providing significant reductions in energy consumption. This should, however, be accomplished without sacrificing the ecological objective of reducing emission of toxic gases or vapors. The heat pipe appliances discussed in this paper accomplish these objectives.*

*The heat pipe concept has been in existence since the early 1940's, though the technical development of heat pipes as they are designed today, did not begin until 1963. Since then, this heat transfer device has received considerable interest for a wide range of applications.*

*At Thermo Electron, under the sponsorship of Southern California Gas Company, heat pipes have been combined with forced combustion and jet impingement heat transfer to produce a group of gas fired residential and commercial appliances. These appliances utilize the isothermal characteristics of heat pipes together with the inherent high efficiency and low emissions of forced combustion systems to provide improved performance compared to contemporary equipment. Included in these appliances are a commercial griddle, an oven for reconstitution of frozen foods, a deep fat fryer, and a water heater.*

*Typical test data for these appliances show carbon monoxide levels of 10 to 100 ppm and total oxides of nitrogen concentration of 5 to 30 ppm.*

*Cooking efficiency for the oven was improved from less than 42 percent for conventional equipment to 54 percent. For the water heater, both operating and standby losses were reduced with the combustion efficiency increased from 70 percent to over 80 percent. Similar improvements were accomplished for the other appliances.*

*These appliances illustrate that heat pipes can be applied in useful and practical designs to provide products with significant advantages over conventional appliances, including improvements in efficiency and emissions, while providing uniformity of temperature and better temperature control.*

## INTRODUCTION

Recently a number of new heat transfer and combustion techniques have been applied to the design of commercial and residential appliances. Many of these approaches had been in existence for some time, but had been applied primarily to space age problems. In this paper, four gas fired appliances are described which utilize heat pipes, powered combustion, and jet impingement heat transfer techniques to improve efficiency and performance while producing low emissions of carbon monoxide and oxides of nitrogen in the flue gases. Included are an isothermal griddle, a deep fat fryer, a food reconstitution oven, and a storage water heater. These products were developed at Thermo Electron Corporation under the sponsorship of Southern California Gas Company.

This paper reviews the basic technology involved in gas fired powered combustion, jet impingement heat transfer, and heat pipes as applied to water heating and cooking appliances. It illustrates that through proper engineering techniques, these technologies can be combined to produce appliance designs which are efficient utilizers of energy and provide superior operating characteristics.

## HEAT PIPES

The heat pipe, which is a spinoff from the United States space/nuclear technology program with significant applications in the civilian market, is a device for transferring heat from point to point with no moving parts. It can possess an effective thermal conductivity thousands of times greater than that of most conductive metals such as aluminum or copper. Because of this high effective thermal conductivity, it can replace many conventional fluid heat transfer systems which require electromechanical pumps for fluid return.

The operation is fundamentally simple and easily understood. There is, however, technical complexity in the design and processing of reliable high performance heat pipes. The technical work started in the early 1940's, and a patent, which is now in the public domain, was issued to R. S. Gaugler in 1944 (Patent No. 2,350,348). The technical development as we know it now, however, did not begin until 1963, when G. M. Grover of Los Alamos Scientific Laboratory independently hit on a similar device and coined the name "heat pipe" to describe it.

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Figure 1 is a schematic drawing of a heat pipe. It is a hollow chamber (not necessarily cylindrical) whose walls include capillary structure, which assists in moving liquid from one point to another and functions much as the wick in an oil lamp. The chamber, which has been evacuated and then sealed, contains a substance (water, organic compounds, or liquid metals) which is in liquid-vapor equilibrium at the heat pipe operating temperature. When heat is applied to one end of the heat pipe, liquid vaporizes, absorbing large quantities of energy and raising the pressure at that end of the pipe. The resultant high pressure drives the vapor to the end of the heat pipe that is cooled, where the vapor condenses and releases the heat absorbed at the heat input end of the heat pipe. Thus, heat is carried from one end of the heat pipe to the other via vapor. The condensed liquid is then returned to the heat input end of the heat pipe by the capillary forces developed in the wick structure. The cycle is then repeated. The result of this process is that large quantities of heat can be transported from one place to another with very little decrease in temperature, and the system is self-contained, thus requiring no external equipment.

## JET IMPINGEMENT

Jet impingement heat transfer techniques have been incorporated in a wide variety of applications, ranging from cooling a thermionic diode to air heating in a hot air furnace. Relatively large heat transfer rates are attainable with jet impingement when compared with nonimpinging flows. The jet impingement concept is also attractive from the design standpoint, allowing flexibility in control of surface heat transfer.

In jet impingement heat transfer, gas flows through a series of holes in an orifice plate, creating many jets. These jets of gas strike the target and the momentum in the jet reduces the thermal boundary layer on the target plate, thereby increasing the heat transfer coefficient. The momentum of the jet striking the target plate plays an important role in reducing the thermal boundary layer thickness. Small hole diameters will increase the momentum of the jet at the exit, but jet spreading can significantly reduce the jet momentum normal to the target surface if the target is far from the orifice plate. Closely spaced, small-diameter jets will provide many local areas of boundary layer reductions, but if the jets are too close to each other, one jet may interfere with the development of the other. If there are too many jets in line with the direction of the outlet flow, the momentum of the "spent gas" (i.e., outlet flow) tends to bend the last rows of jets, reducing the momentum component normal to the plate. Thus, the optimum heat transfer design requires judicious iterations of orifice diameter, orifice-to-orifice spacing, and orifice plate-to-target plate distance. These jet impingement parameters are shown pictorially in figure 2.

In the design of appliances, it is desirable to mini-

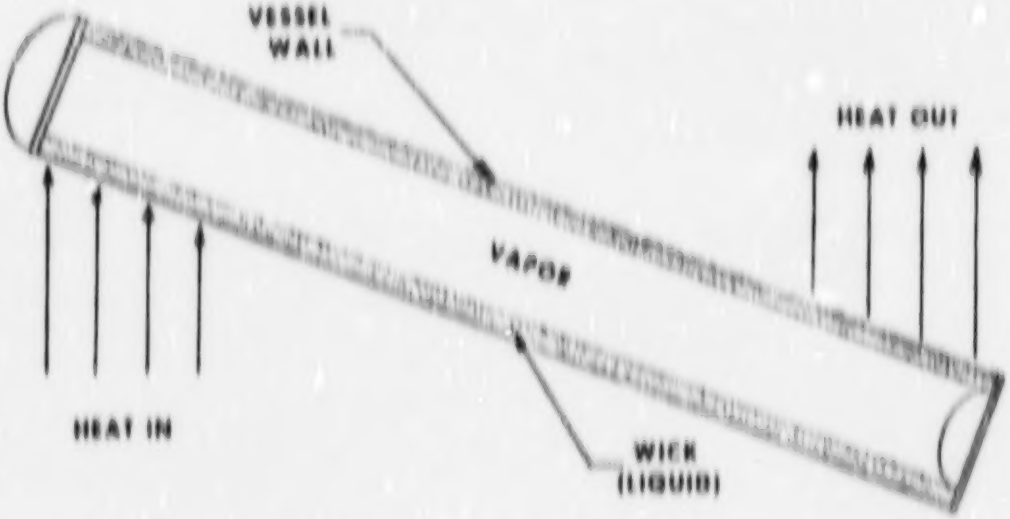

Figure 1. Heat pipe.

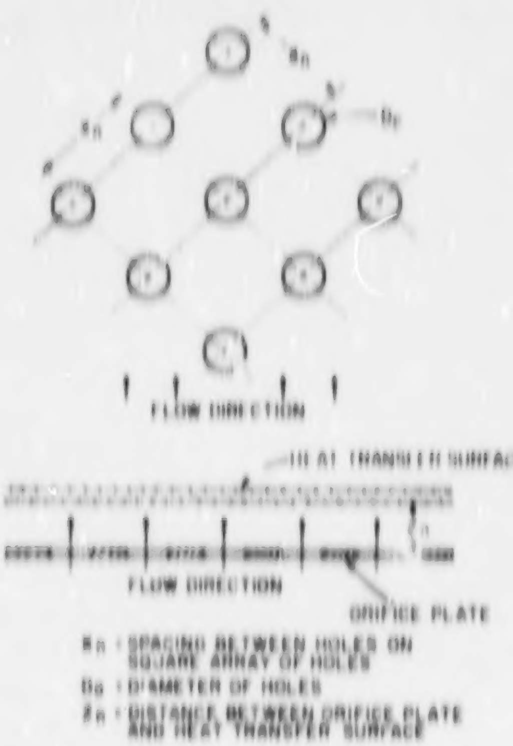
Sn
Dn
FLOW DIRECTION
HEAT TRANSFER SURFACE
Zn
FLOW DIRECTION
ORIFICE PLATE
Sn = SPACING BETWEEN HOLES ON SQUARE ARRAY OF HOLES
Dn = DIAMETER OF HOLES
Zn = DISTANCE BETWEEN ORIFICE PLATE AND HEAT TRANSFER SURFACE

Figure 2. Jet impingement parameters.

mize pressure drop at a given flow rate while maintaining the highest possible heat transfer coefficient.

Because of its apparent advantages, an experimental program was undertaken to investigate the heat transfer characteristics of jet impingement heat transfer. The experimental study yielded some very promising results with heat transfer coefficients of over 40 Btu/hr ft$^2$ °F for very moderate pressure drop.

## POWERED COMBUSTION

To fully take advantage of potential improvements in efficiency and size reduction for gas-fired appliances made possible by use of heat pipe and jet impingement technologies, a third technique is needed: powered combustion. This also permits control of gaseous emissions within satisfactory limits.

Atmospheric burners have been used in almost all residential and commercial gas-fired appliance designs used in contemporary equipment. The required combustion volume has been determined by the energy available at the burner for mixing air with gas to permit the combustion reaction. The pressure drop available in the heat transfer system has been limited to the buoyancy force available in the column of flue gases. This results in relatively low velocity in the gas stream and, therefore, low heat transfer coefficients between the flue gases and the transfer surface. The lower pressure drops available also determine the diameter of vent needed, since again, only buoyancy forces are available to perform this function. The use of powered combustion provides precise control of the fuel-air ratio through the use of premix and a zero governor. This then permits a high heat release rate per unit volume of combustion chamber. Since buoyancy forces are not important, only small diameter vent lines are needed and can run up, down, or horizontally. Heat losses due to natural draft through the appliance vent are thus eliminated. Typically, a power vented appliance of 100,000 Btu/hr capacity can use a 2 inch diameter vent as compared to a 6 inch diameter flue for a natural draft design. The premix, nonquenching burner with accurate control of excess air produces significantly lower levels of oxides of nitrogen than conventional atmospheric burners.

With the pressure drop available from the use of powered combustion, heat transfer coefficients can be significantly increased, so transfer surface and therefore appliance size can be reduced, while achieving efficiency levels not possible with atmospheric burner systems.

## APPLIANCE DESIGN

Four gas-fired appliances utilizing the techniques of jet impingement and forced combustion in heat pipe designs will be described. All provide efficiency levels and performance features not attainable in contemporary appliances.

## GAS FIRED HEAT PIPE GRIDDLE

A recent development program has resulted in a unique 2 foot by 3 foot gas fired cooking griddle shown in the photograph in figure 3.[1] The griddle consists of a heat pipe cooking surface and a combustion chamber. The heat pipe cooking surface is a hermetic assembly which contains the heat pipe fluid under its own vapor pressure. Capillaries on the bottom of the container, made from a series of copper screens, allow for the proper distribution of the fluid over the entire heated surface. The combustion chamber utilizes the principles of a highly efficient system, which consists of a premixed forced combustion burner used in conjunction

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[1] Exclusive manufacturing rights in the United States and Canada have been granted to U.S. Range, Inc., Gardena, California.

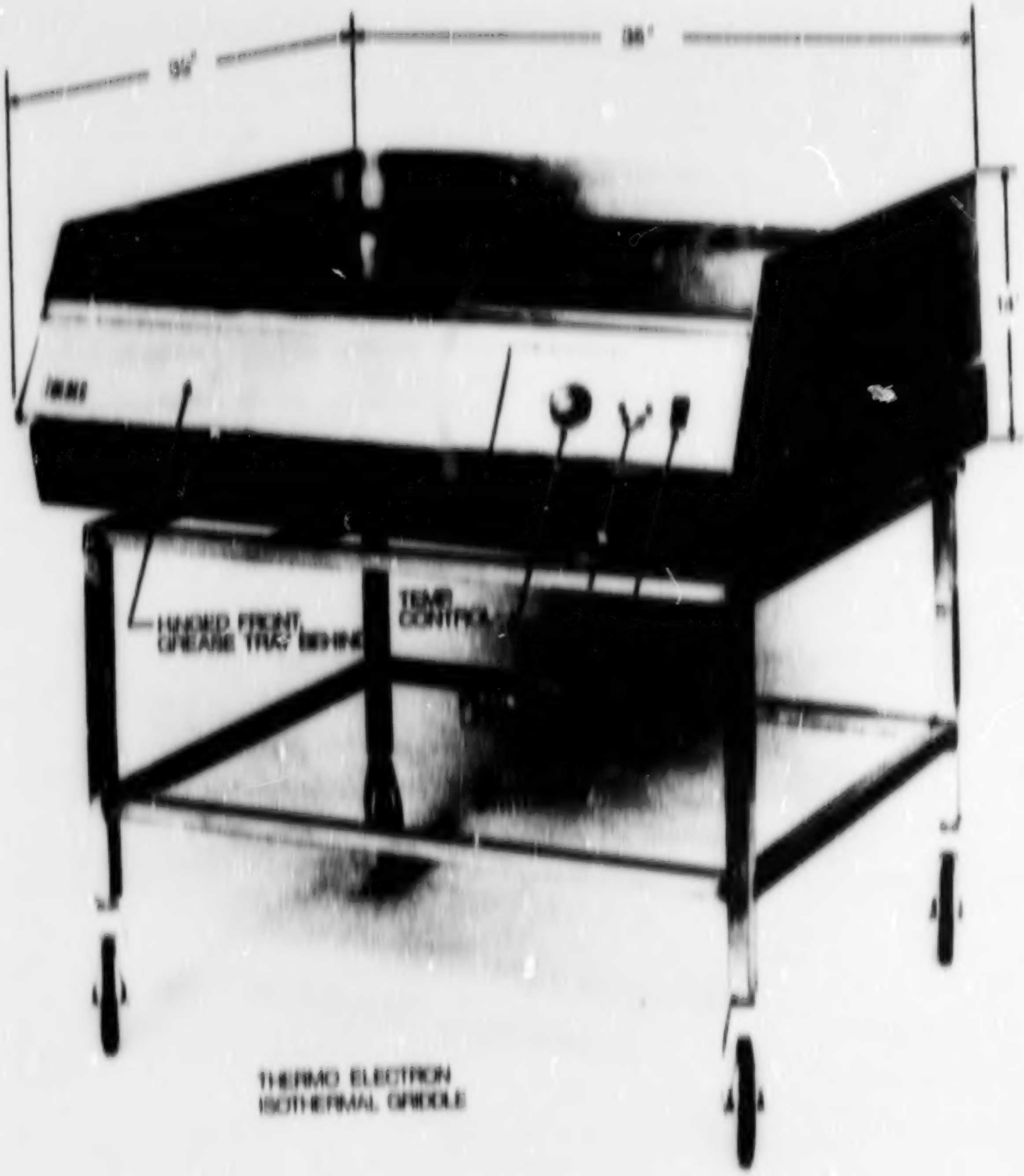
35"
36"
14"
HINGED FRONT
GREASE TRAY BEHIND
TEMP
CONTROLS
THERMO ELECTRON
ISOTHERMAL GRIDDLE

Figure 3. Gas-fired heat pipe griddle.

with a series of jet impingement stages for the purpose of heating the lower surface of the heat pipe so that the flue products can be power vented. The combustion and temperature control system consists of an off-on pressure switch, which, sensing the heat pipe pressure, activates the combustion blower, the gas solenoid, and the ignition system. The gas flow to the burner is proportional to the motor speed to yield a constant gas/air ratio by allowing the gas to be drawn through a zero governor and fixed orifice into the combustion blower. In addition to the primary thermostat, there is an overpressure switch which cuts the main power as the evaporator vapor pressure approaches one atmosphere.

Table 1 is a comparison between the operation of the heat pipe griddle and that of a conventional gas-fired griddle of the same size. The results show that the heat pipe griddle heats up in one-fourth the time, its efficiency is twice as high, it consumes one-third of the fuel on standby operation, its surface temperature variation is an order of magnitude lower, and its cabinet surface temperatures in all places are lower than those of the conventional griddle.

Table 1. Performance comparison of heat pipe griddle versus conventional griddle

| | Heat pipe griddle | Conventional griddle |
|---|---|---|
| Initial gas input, Btu/hr | 83,000 | 85,000 |
| Control gas input, Btu/hr | 36,000 | 32,000 |
| Time to reach 400° F, minute | 7 | 26 |
| System efficiency, percent | 81 | 40 |
| Steady state gas consumption, Btu/hr | 12,000 | 32,000 |
| Control type | high-low/off-on | high-low/continuous |
| Control accuracy, °F | ± 10 | ± 30 |
| Control temperature variation, °F | ± 5 | ± 25 |
| Surface temperature variation, °F[a] | ± 2.5 | ± 25 |
| Cabinet temperature, °F | 240 | 350 |
| Exhaust temperature, °F | 430 | 580 |
| Excess $O_2$, percent | 5.5 | 18 |
| Exhaust CO, percent | 0.001 | 0.002 |
| Exhaust $CO_2$, percent | 8.7 | 1.6 |

[a] Not including the corners of the unit.

A temperature profile of the heat pipe griddle surface was measured while the unit operated at a control setting of 345 °F. The results of this measurement have been plotted in figure 4. The plot shows that the entire surface is essentially constant except at the extreme corners, which are lower by 15° F.

These results dramatically establish the feasibility of using the heat pipe principle to produce efficient, isothermal cooking equipment.

## HEAT PIPE OVEN

The frozen food reconstitution oven, shown in figure 5, consists of a heat pipe and a sealed gas-fired combustion system. The heat pipe forms the internal cavity of the oven, which measures 36 inches wide x 24 inches deep x 12 3/4 inches high and contains three shelves spaced 4 inches apart. The entire oven cavity is surrounded by 2 inches of fibrous insulation to minimize heat leakage. This produces overall dimensions of 40 inches wide by 28 inches deep by 25 inches high. The front of the oven is sealed by two hinged, insulated doors which swing out of the way to allow access to the oven.

The combustion system is similar but not identical to the combustion system used on the isothermal griddle. It consists of a forced combustion burner and jet impingement heat transfer stages and is capable of firing rates up to 50,000 Btu/hr and combustion efficiencies of 80 percent. The overall efficiency of heating food is 54 percent as compared to less than 45 percent for conventional ovens.

The fundamental principle of operation of the oven consists initially of transferring heat from a gas-fired combustion system to the heat pipe evaporator. The working fluid in the evaporator is vaporized and travels to the condenser surfaces. The vaporized working fluid is condensed, then returned by gravity and capillary action to the evaporator. Heat is transferred to the food by radiation, conduction, and convection. This system is capable of maintaining a constant and uniform temperature in the oven cavity over a range of 200° F to 450° F.

By employing the heat pipe principle in its design, this oven possesses the following advantages:

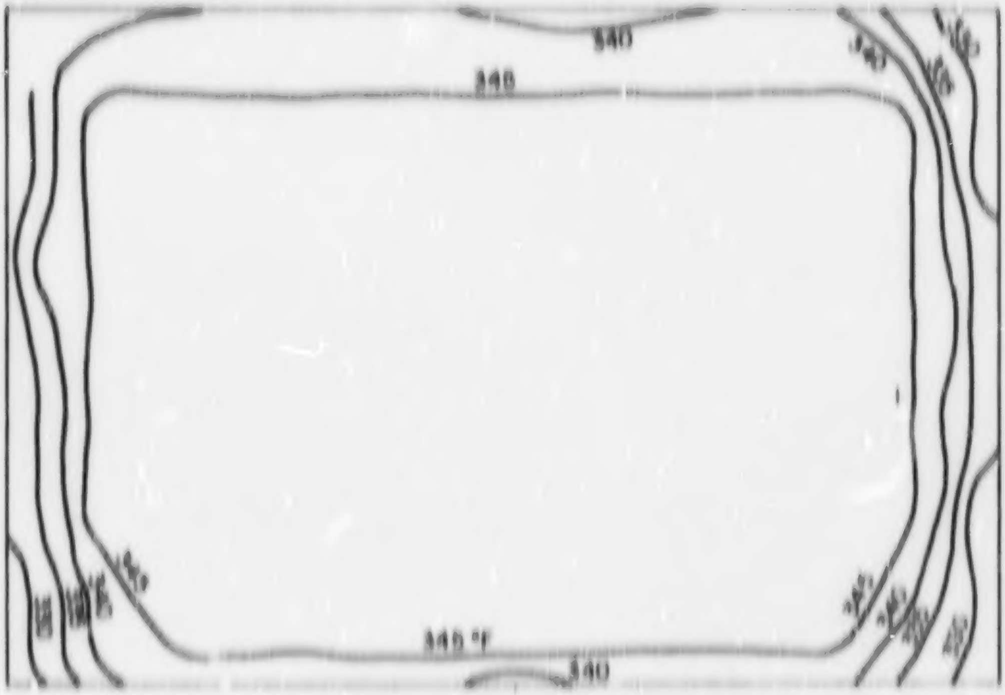

Figure 4. Surface temperature distribution of heat pipe griddle, 36 in. x 24 in.

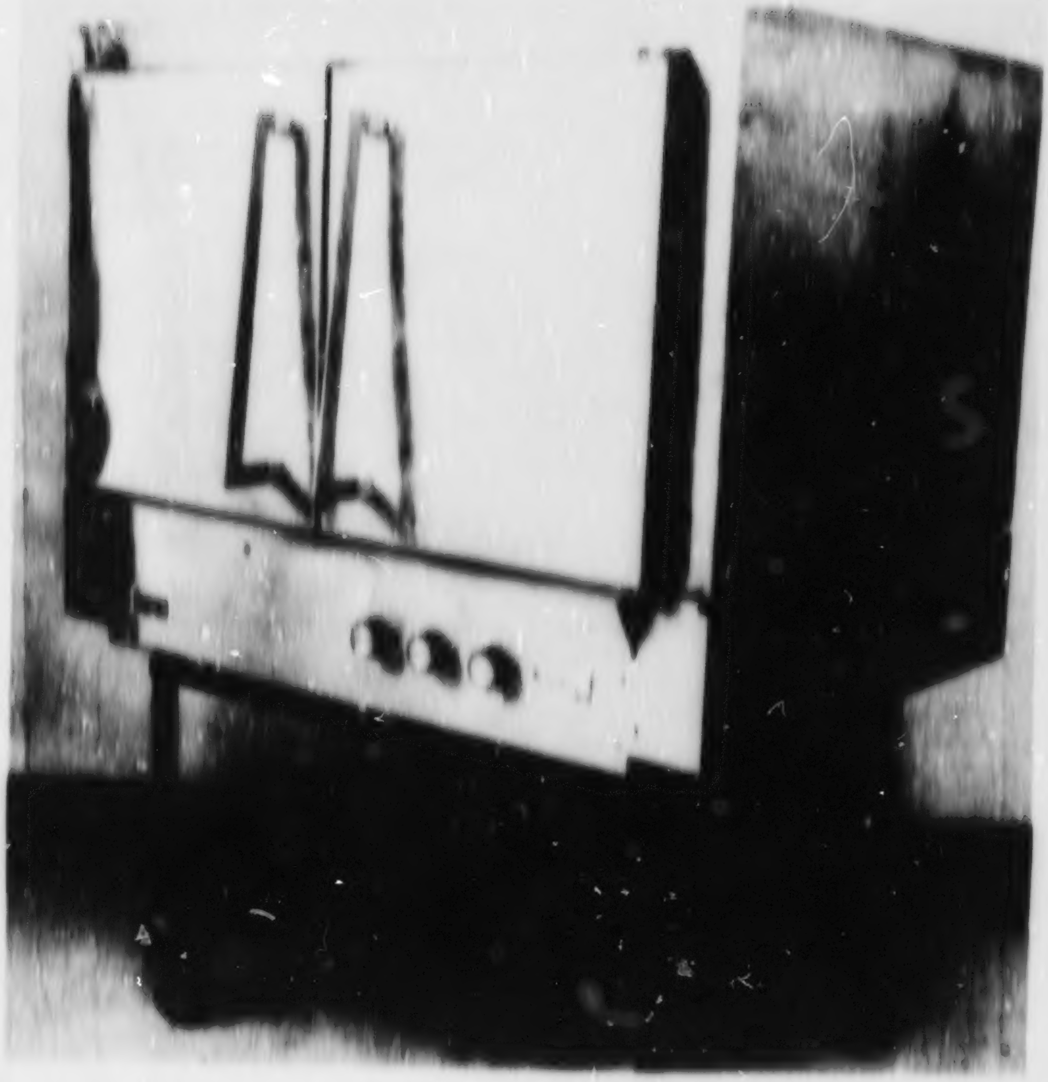

Figure 5. Photograph of heat pipe oven.

1. Temperature uniformity independent of the food's position in the oven;
2. Maintenance of high humidity content;
3. Elimination of the large blower used in convective ovens; and
4. Reconstitution time of frozen foods independent of position in the oven.

These advantages improve the overall quality of the food, particularly when large quantities of food must be prepared.

## HEAT PIPE DEEP FAT FRYER

The heat pipe deep fat fryer is illustrated in figure 8. The appliance consists of a heat pipe fry tank, a sealed combustion chamber, and gas controls, all contained in package measuring 16 inches wide x 28 inches deep x 14 inches high. The fry tank, measuring 14 inches wide x 16 inches deep x 8 1/2 inches high, contains an integral heat pipe covering its entire bottom and back. The heat pipe contains wicking on the evaporator surface to distribute the fluid uniformly over the entire evaporator area. The bottom of the fry tank is pitched slightly to allow for drainage at the front of the unit. A cold zone for the accumulation of food particles is provided at the front of the tank. The use of the heat pipe eliminates the need for fire tubes in the fry tank, which in turn reduces the required height of the tank and facilitates cleaning. The heat pipe is capable of providing closely controlled and uniformly distributed temperatures in the fry tank; these features enhance the quality of the cooking and the longevity of the cooking oil.

The combustion chamber consists of a premixed gas-fired burner and jet impingement heat transfer stages contained in a sealed insulated housing which surrounds the entire heat pipe section of the fry tank.

The performance of the heat pipe fryer was as follows:

Frying Performance

| | |
|---|---|
| Input from fuel | 60,000 Btu/hr |
| Efficiency, based on flue analysis | 77 percent |
| Energy requirement, AGA method | 900 Btu/lb |
| Frying rate, raw-to-done potatoes | 84 lb/hr |

This unit provides a gas-fired deep fat fryer which is:

1. as compact as comparable electric units,
2. more efficient than current gas-fired units,
3. much lower in cooking oil breakdown than either gas or electric units,
4. easy to clean and maintain, and
5. economical to operate.

## HEAT PIPE WATER HEATER

Contemporary gas-fired storage water heaters are normally constructed with glass-lined steel tanks protected from corrosion by a sacrificial magnesium anode. The residential models include a flue, usually from 3 to 4 inches in diameter, extending through the tank and terminating in a vent hood connection at the top. The flue and bottom head assembly are glass-lined in a separate operation from the shell and top head assembly, and then the two subassemblies are welded together. A combustion chamber is attached to the bottom of this tank, the tank is insulated, an outer enameled steel jacket is added, and an atmospheric-type gas burner and control system are installed. Commercial heaters differ in that they either use a number of internal flues (as many as 10) or pass the flue gases around the outside of the tank in a "floater" design in order to accomplish the higher heat transfer required in commercial installations.

While designs of this type have provided reasonable performance for many years, they are subject to certain problems, as summarized in table 2.

Because the glass coating cannot cover all of the steel surfaces in the assembled tank, some bare areas occur which would corrode rapidly if they were not protected. For this reason, a magnesium anode is installed in the tank to provide additional corrosion protection. The anode has limited life, however, especially in some waters, so this, together with the solubility of the glass coating in water, determines the life of the heater.

The anode itself may create a problem since, in some waters, it promotes a type of chemical reaction which can cause odor and taste problems in the water.

Scale formations can create problems in both commercial and residential designs. In commercial designs, because of the high heat flux required, actual burnouts or thermal stress failures can occur in waters with high dissolved solid concentrations if the heater is not cleaned frequently. In residential designs, the scale buildup is more apt to result in an objectionable "rumbling" noise.

Both the center flue and floater designs result in a continuous heat loss from the stored water when the burner is not operating. The flue is at essentially stored water temperature and promotes a thermal circulation of air through the flue and out the vent system. This can result in a service efficiency of less than 40 percent, even though the flue gas losses during burning are less than 30 percent.

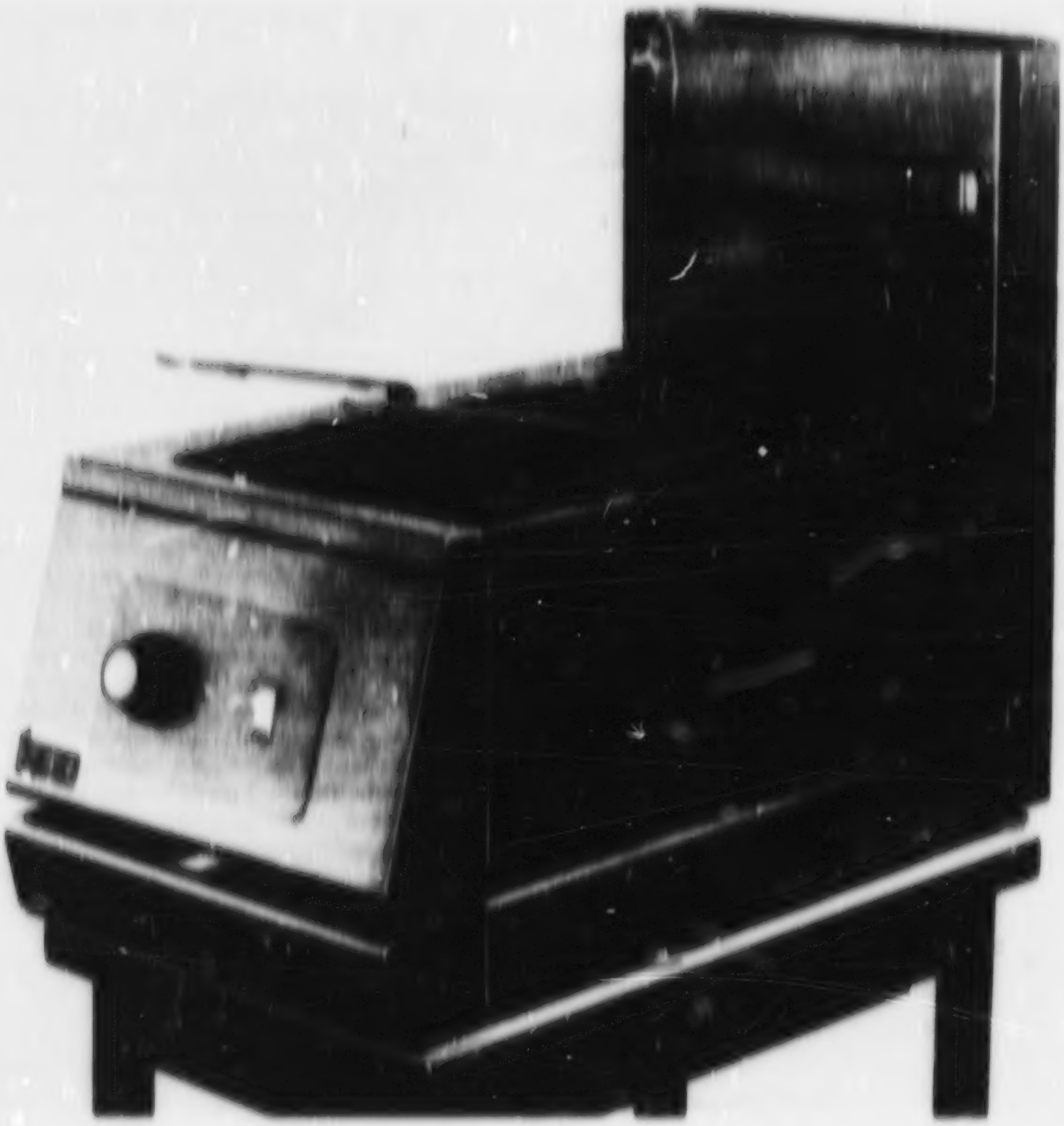

Figure 6. Photograph of heat pipe deep fat fryer.

Table 2. Advantages of heat pipe water heaters

| Conventional design problem | Cause | Solution |
|---|---|---|
| 1. Corrosion | Solubility of tank coating and anode life limits tank life. | With heat pipe design, heat source is separated from tank construction, so different materials can be used with longer life than steel. |
| 2. Rumbling | Scale accumulation causes bubble formation which shakes heater. | More uniform temperature reduces scale formation. Bottom head heat transfer is not used, so heat is not transferred through heavy scale deposits. |
| 3. Efficiency | Heat losses from exposed flue surface result in high standby losses causing service efficiency of less than 40 percent in some cases. | No flue passageways exist in the heater, so service efficiency will approach recovery efficiency (approximately 70 percent). |
| 4. Large vent system | Conventional gravity combustion system requires large diameter vent and chimney. | Power combustion system requires no chimney, and uses a small diameter vent line. |
| 5. High surface temperature | Conventional burner and combustion system makes containment of heat difficult in combustion chamber area. | With forced combustion, a simple chamber can confine the heat of combustion eliminating hot jackets. |
| 6. Taste and odor | In some waters, use of magnesium anodes promotes a chemical reaction which causes unpleasant odor and taste. | With nonsteel tank construction, an anode is not required. |

The use of gravity vent systems requires connection to a chimney, as well as a large diameter flue pipe, and large vent hoods, especially in the case of high input commercial designs.

Surface temperatures of the heater jacket in the combustion chamber area are difficult to restrict to reasonable levels.

In the proposed design, heat is transferred from the products of combustion to the water by a heat pipe. This permits separation of the primary heat source from the tank construction, thereby permitting greater flexibility in selection of tank materials. Molded, reinforced plastic materials can be considered which are not subject to thermal or chemical degradation by the water; thus, heater life can be improved and use of anodes can be eliminated.

Since the heat pipe design can result in elimination of flue passageways in the water heater, the attendant standby losses caused by air flow through the heater can be eliminated. Service efficiency can be improved from 40 percent to values near 70 percent. In addition, the use of a heat pipe for transferring heat from the flue gases to the water should reduce scale formation and permit easier cleaning.

The use of a forced combustion jet impingement heat transfer system will eliminate the requirement for a conventional chimney. Since the heat of combustion can be confined to a simple chamber in this system, the jacket temperature problems can be eliminated.

Figure 7 illustrates the heat pipe-water heater concept. The heater shown consists of a plastic, 40-gallon storage tank with a conventional plastic cold water dip tube, a drain valve, and an immersion thermostat. The tank is coated with a "foamed in place" insulation which also serves as the heater jacket. The tank rests on a cylindrical base which contains the combustion system and heat pipe assembly.

The combustion system consists of a 40,000-Btu/hr

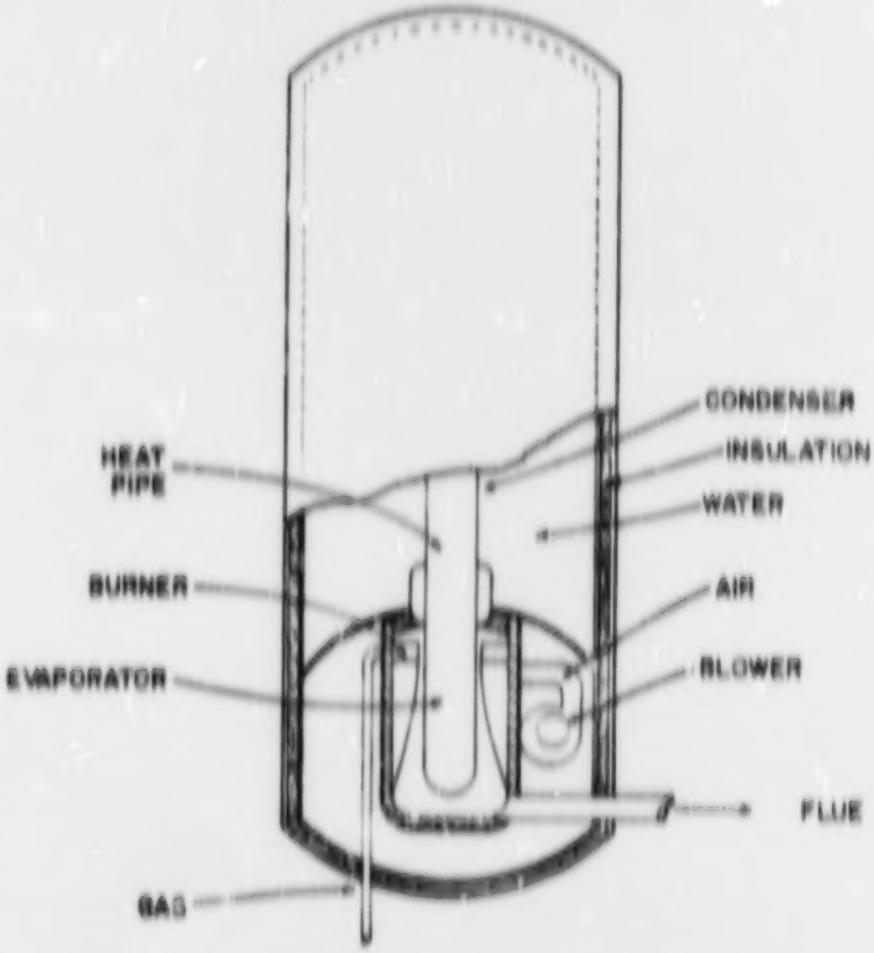

Figure 7. Heat pipe storage water heater.

forced draft burner which directs hot flue products across the evaporator surface of a heat pipe. The flue gases are then collected and exhausted through a 1 1/2 inch diameter vent pipe.

## FORCED COMBUSTION EMISSIONS

An important consideration in any new appliance design is the level of emissions in the flue gases. Of particular interest is the concentration of oxides of nitrogen. Table 3 gives $NO_x$, NO, and $NO_2$ levels for three of the designs discussed in this paper as a function of oxygen level in the flue gases. The recorded $NO_x$ levels are distinctly lower than for conventional appliances using atmospheric burners. Typical carbon monoxide levels for these appliances range from 10 to 100 ppm.

## SUMMARY

This paper has used four new gas-fired appliance designs, a water heater, a griddle, an oven, and a fryer, to illustrate the ability of heat pipes, combined with new heat transfer techniques, to provide substantial improvements in efficiency and emissions, as well as performance features in practical equipment designs.

Table 3. Oxides of nitrogen emission from forced combustion appliances

| | Heat pipe oven | | Heat pipe fryer |
|---|---|---|---|
| Gas input, Btu/hr | 86,000 | 88,000 | 67,000 |
| Exhaust $O_2$, percent | 6.5 | 3.2 | 6.5 |
| Exhaust $CO_2$, percent | 8.0 | 9.9 | 8.0 |
| $NO_x$, ppm | 17.5 | 104 | 13.5 |
| NO, ppm | 16.5 | 100 | 13 |
| $NO_2$, ppm | 1.0 | 4 | 0.5 |

| | Water heater | | | | | | |
|---|---|---|---|---|---|---|---|
| Gas input, Btu/hr | 38,800 | 36,700 | 38,600 | 38,700 | 38,800 | 38,800 | 38,400 |
| Exhaust $O_2$, percent | 3.3 | 4 | 4.8 | 5 | 5.2 | 5.5 | 6 |
| Exhaust $CO_2$, percent | 9.2 | 8.9 | 8.5 | 8.3 | 8.2 | 7.9 | 7.6 |
| $NO_x$, ppm | 82 | 21 | 16.5 | 12 | 10.0 | 8.0 | 5.8 |
| NO, ppm | 75 | 18.5 | 15 | 10.5 | 9.5 | 7.5 | 5 |
| $NO_2$, ppm | 7 | 2.5 | 1.5 | 1.5 | 0.5 | 0.5 | 0.8 |

6 November 1975

## Session VI:

## NEW INDUSTRIAL PROCESSES

G. Ray Smithson*
Session Chairman

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# PROPERTIES OF INDUSTRIAL FUEL GASES MANUFACTURED FROM COAL USING COMMERCIALLY PROVEN TECHNOLOGY

James I. Joubert, Ph.D., and Daniel Bienstock[1]

## *Abstract*

*Gaseous fuels have been manufactured from coal for well over a century. Although coal gasification was once widely employed in the United States, the advent of inexpensive natural gas and petroleum in the 1920's and 1930's virtually eliminated such processes.*

*Industry, which consumes about 45 percent of our natural gas production, is now faced with curtailments in supplies of this fuel. Fuel gases of low (150 Btu/ft$^3$) and medium (300 Btu/ft$^3$) heating value could be substituted for natural gas in many industrial applications. Such fuel can be manufactured from coal using existing, well-proven technology.*

*This paper discusses the properties of coal-derived fuel gases relevant to combustion processes. General relations are presented that show that the combustion properties are mainly a function of the fuel gas heating value, and are largely independent of the process and coal used for production of the fuel gas.*

*Various types of commercial coal gasifiers, gas cleanup systems, and gasification costs are discussed briefly. Approaches to utilization of an integrated gasification system, as well as problems to be anticipated in retrofit applications, are also considered.*

## *Introduction*

A great deal has been written about America's energy situation within the last 2 years. Numerous articles have appeared discussing alternate energy sources such as solar, geothermal, oil shale, synthetic natural gas, and oil from coal. Unfortunately, it appears now that more than a decade will pass before any of these approaches could make a significant contribution to meeting our energy requirements.

The question remains, then: What can be done now, with existing technology and resources, that will begin to make an impact on our Nation's energy problems in the near term?

First, let us examine the situation with respect to our fossil fuel resources. It is well known by now that our domestic reserves of oil and natural gas are dwindling and that we are becoming increasingly dependent on foreign sources, particularly in the case of oil. It is likely that suitable economic incentives could alter the situation somewhat, but this is speculative at this point.

It is also well known that coal represents our largest indigenous fuel reserve. Estimates of the amount of coal economically recoverable indicate that this fuel would last 300 to 600 years even if consumed at a rate equal to our present and anticipated future total energy demand. At the moment, coal contributes only about 18 percent of the energy utilized in the United States annually.

The reasons why coal contributes such a small amount to our energy needs are fairly evident. It is impractical for use in the transportation sector (i.e., the automobile). The cleanliness and convenience of gas and oil have largely displaced coal from domestic and commercial use. For the same reasons, gas and oil are preferred by industry. In addition, because of its ash and sulfur content, coal is simply not suitable for certain manufacturing operations. With increasingly more strict pollution regulations, there has been a trend toward displacement of coal from electric power generation facilities.

There are, therefore, three main reasons why coal occupies its present position in the energy picture: (1) it is a solid fuel, and somewhat difficult to handle; (2) it is a dirty fuel—much of our coal has a high sulfur and ash content; (3) the more convenient fossil fuels, natural gas and oil, have been available at lower or reasonably competitive rates.

However, the situation has been changing rapidly with respect to item (3) listed above. If coal could be converted to a clean gaseous fuel, the problems associated with the direct use of coal would be largely eliminated.

It is the purpose of this paper to discuss the major aspects of utilizing clean fuel gases manufactured from coal using existing technology. By clean fuel gases it is meant gases with heating values ranging from about 150 to 300 Btu/ft$^3$. This type of fuel gas is not to be confused with "high-Btu" gas made from coal, (1,000 Btu/ft$^3$), which presently is the subject of intensive research.

To determine whether utilization of the fuel gases of the type described could contribute significantly to meeting our energy needs, let us examine how energy is consumed in the United States. Figure 1 gives a breakdown of energy production and consumption during 1971. While current figures may differ somewhat from those indicated, the situation probably remains essentially unchanged on a relative basis.

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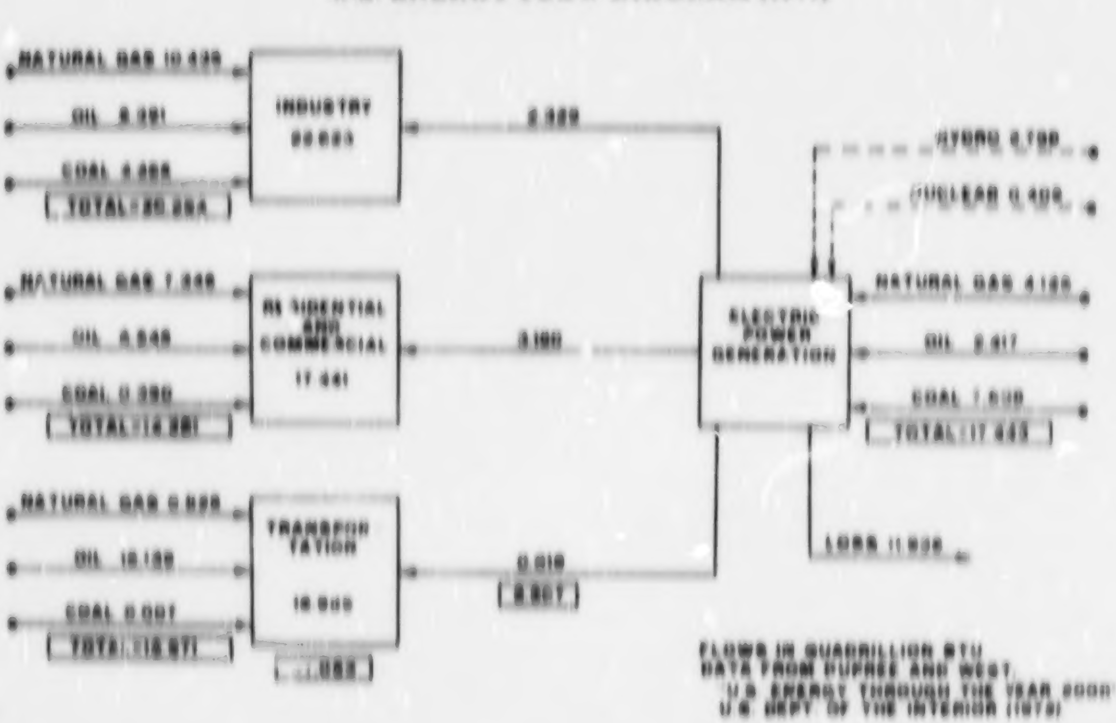
Looking first at the electric power generation sector, we see that significant amounts of natural gas and oil are consumed for generation of electricity. From an energy policy point of view, this is not defensible and, in fact, efforts are being made to encourage use of coal (with stack-gas scrubbing). This sector represents a large market for coal-derived fuel gases and there is presently a major research program directed toward utilizing such fuels in combined gas turbine-steam turbine power cycles.

Because of the properties of coal-derived gases (to be discussed), it does not appear that their use in the residential/commercial sector would be attractive. The use of natural gas and oil in this sector is justifiable. Similarly, no application of coal-derived gases in the transportation sector is apparent.

It is the industrial sector of the economy that is the major consumer of energy in the United States. Industry consumes about 18 percent of the oil, 36 percent of the coal, and 45 percent of the natural gas utilized in the United States each year. Only about 14 percent of the total energy input goes to nonfuel uses, i.e., feed stocks (ref. 1); approximately 50 percent is used for steam generation for process or space heating and about 34 percent is used in direct heat applications (ref. 2).

Fully 93 percent of the natural gas used by industry is burned in process furnaces or in boilers. In some industries, natural gas is consumed wastefully; frequently, only 5 to 25 percent of the heating value of the fuel is utilized in a process (refs. 3,4).

It is the authors' belief that the proper use of natural gas is primarily within the residential/commercial sector. In the discussion to follow, it will be shown that the technology exists to produce substitute fuels from coal that will be suitable for most industrial purposes. The utilization of coal-derived gases would permit displacement of natural gas from industrial to more effici


U.S. ENERGY FLOW DIAGRAM (1971)
NATURAL GAS 10.435
OIL 5.391
COAL 4.288
TOTAL 20.254
INDUSTRY
20.623
2.329
NATURAL GAS 7.348
OIL 6.548
COAL 0.380
TOTAL 14.281
RESIDENTIAL AND COMMERCIAL
17.441
3.160
NATURAL GAS 0.826
OIL 16.139
COAL 0.001
TOTAL 16.971
TRANSPORTATION
16.969
.003
0.016
2.907
HYDRO 2.798
NUCLEAR 0.405
ELECTRIC POWER GENERATION
NATURAL GAS 4.180
OIL 2.617
COAL 7.839
TOTAL 17.443
LOSS 11.636

FLOWS IN QUADRILLION BTU
DATA FROM DUPREE AND WEST,
"U.S. ENERGY THROUGH THE YEAR 2000"
U.S. DEPT. OF THE INTERIOR (1972)

Figure 1. U.S. energy flow diagram (1971).

ent end uses, as well as provide an alternate fuel for industries presently experiencing curtailments in natural gas supplies.

*History of Coal Gasification*

Despite the publicity generated by various novel coal gasification schemes in recent years, the technology is hardly a new one. Coal has been gasified, using one technique or another, for nearly 175 years.

A list of the various types of fuel gases that have been manufactured from coal is given in table 1. The compositions and heating values indicated are only typical and may vary somewhat depending on the coal and the equipment used to manufacture the gas.

***Coal gas,*** *or* ***retort gas,*** was made by heating coal in the absence of air. It appears that the principal involved was discovered as early as 1609 (ref. 5). This was the first type of fuel gas manufactured for public distribution, with gas light companies being established in London in 1807 and in Baltimore in 1816. The process involved, however, was not very efficient from the point of view of gas production; most of the coal was converted to coke.

***Coke oven gas*** results from the distillation of coal in byproduct coke ovens and is quite similar to retort coal gas. Again, the main product of the coke oven is coke, but with larger yields of other products than in retort processes. In the 1930's and 1940's, coke oven gas represented a significant portion of the manufactured gas distributed by gas utilities (ref. 6). Today, coke oven gas is consumed largely within the steel industry.

***Blue water gas*** was produced by reaction of steam with incandescent carbon. The process was intermittent, consisting of periods in which the fuel was heated with air, and gasmaking periods during which steam was passed through the hot fuel bed. Blue water gas was used largely as a raw material in the production of carburetted water gas.

***Carburetted water gas*** was made by enriching blue water gas with the gaseous decomposition products of various oils. This raised the heating value to 530 to 560 Btu/ft$^3$, which met the minimum requirements for dis-

Table 1. Coal-derived fuel gases

| | Percent by volume | | | | | | | Heating value[b] (HHV) Btu/SCF |
|---|---|---|---|---|---|---|---|---|
| | $CO_2$ | $O_2$ | $CO$ | $H_2$ | $CH_4$ | Ill.[a] | $N_2$ | |
| Coal gas (retort) | 2.4 | 0.6 | 7.4 | 48.0 | 27.1 | 3.0 | 11.3 | 542 |
| Coke oven gas | 2.0 | 0.3 | 5.5 | 51.9 | 32.3 | 3.2 | 4.8 | 569 |
| Blue water gas | 5.4 | 0.7 | 37.0 | 47.3 | 1.3 | 0.0 | 8.3 | 287 |
| Carburetted water gas | 5.5 | 0.0 | 32.5 | 37.0 | 12.0 | 9.0 | 4.0 | 540 |
| Producer gas (air/steam) (low-Btu gas) | 4.5 | 0.6 | 27.0 | 14.0 | 3.0 | 0.0 | 50.9 | 163 |
| Synthesis gas ($O_2$/steam) (medium-Btu gas) | 12.8 | 0.3 | 53.3 | 30.9 | 0.4 | 0.0 | 2.3 | 275 |

[a] Illuminants: $C_2H_4$, $C_3H_8$, $C_3H_6$, etc.

[b] SCF at 60° F, 1.0 atm.

tribution. This was the only commercial process employed in this country with the sole purpose of producing gas for distribution by gas utilities.

It is the utilization of producer gas and synthesis gas that is the main subject of this paper.

*Producer gas*, made by the steam/air gasification of coal, is generally recognized as the cheapest form of coal-derived fuel. Typical heating values range from 130 to 180 Btu/ft$^3$ (*low-Btu gas*).[1]

If pure oxygen is used in place of air, *synthesis gas*, or *medium-Btu gas* results with heating values ranging from 280 to 330 Btu/ft$^3$. Unlike low-Btu gas, this fuel has not been produced commercially in the United States, although it has been used for a number of years in other countries, mainly as a feedstock in chemical plants. Its production on a large scale was not feasible until the advent of tonnage oxygen plants.

Unlike the processes involved in the manufacture of other coal-derived gases, production of low- and medium-Btu gas is continuous and efficient. Virtually all of the combustible material in the coal can be converted to gaseous fuel.

It appears that the first commercial gas producer was constructed by Bischof in Germany, in 1839 (ref. 7). Units were subsequently built by Ebelmen in France (1840), and by Ekman in Sweden (1845).

The first large-scale use of gas producers was brought about by the Siemens brothers in Germany, who demonstrated their combined gas producer/brass furnace in 1861. By 1881, applications of producer gas included firing in small industrial furnaces, and power generation by means of gas engines.

The many advantages of a gaseous fuel over a solid fuel, such as coal or wood, caused rapid acceptance of gas producers in many manufacturing operations. By the mid-1920's, about 150 companies were engaged in the design and supply of producer gas equipment (ref. 7). During that period, approximately 11,000 units were operating in the United States alone (ref. 8); these were employed principally in the steel, glass, ceramics, lime, metallurgical, and chemical industries. About 1,000 gas producers were being used for power generation at that time.

It appears that utilization of producer gas reached its peak in 1920 (ref. 9). Natural gas and petroleum already were being used to a large extent in industry; the costs and increasing availability of these fuels left little incentive for additional investment in producer gas facilities. Coke-oven gas was used increasingly within the steel industry (the major user of gas producers).

It is estimated that by 1930 about 7,000 gas producers remained in continuous operation (ref. 9). By 1948, the number had dwindled to fewer than 2,000; about three-fourths of these were considered obsolete (ref. 8).

Today, there are only a few gas producers remaining in the United States. These are used intermittently or are kept in standby condition.

Fortunately, because of the lesser availability of oil and natural gas in other countries, development of gas producers has continued over the past several decades. A number of modern systems are now considered commercially available in the United States. A brief description of each is given in the next section.

### *Current Commercial Gasification Technology*

### A. Operational Aspects of Commerical Coal Gasifiers

The coal gasification systems presently commercially available may be categorized according to the three basic ways in which the coal is processed: (1) fixed-bed; (2) fluid-bed; and (3) entrained-flow. While many variations are possible, some general comments can be made regarding these basic types that may aid in judging the suitability of a given gasifier for a particular application.

1. Fixed-bed gasifiers

Fixed-bed gasifiers are generally recognized as the most efficient devices for converting a solid fuel into a combustible gas. In a fixed-bed gasifier, the fuel flows countercurrent to the gasifying medium, which promotes efficient transfer of chemical energy from the fuel to the final product gas. An extremely high carbon conversion is usually achieved due to the long residence time of fuel in the reaction vessel. Because of the relatively low gas velocities in the system, the carryover of solids is generally small. Off-gas temperatures range from 800°-1,200° F, which should lead to lower efficiency losses than in other gasifier types if it is necessary to cool the gas prior to cleanup.

A criticism of fixed-bed gasifiers has been that they are not able to gasify caking coals. While this may be generally true, it appears that if a fixed-bed unit is equipped with a suitable stirring device such coals can be successfully processed. Usually, carefully sized fuels must be used with a minimum of fines. The ash fusion temperature of the fuel imposes an upper limit on maximum bed temperature, which may preclude the processing of fuels of low reactivity.

Usually tar is produced in the lower temperature regions near the top of fixed-bed units; this could cause problems in downstream components.

Because of the generally small throughputs possible with fixed-bed gasifiers, these units are most suitable for small fuel consumers or in situations where multiple units are deemed desirable.

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[1] The terms low-Btu gas and medium-Btu gas are not well defined, but are used here to facilitate discussion.

### 2. Fluid-bed gasifiers

The principal advantages of fluid-bed gasification of coal are claimed to be: the ability to gasify coals with a broad range of particle sizes; a high rate of gasification per unit cross sectional area; operability over a wide range of throughputs without a significant loss in efficiency; and good temperature control due to particle mixing within the bed.

On the other hand, because the exit gas is essentially in thermal equilibrium with the solids in the bed at gasification temperature (1,800°-2,000° F), there is a considerable loss of thermal energy from the gasifier proper. This energy must be recovered in downstream components to maintain reasonable efficiency. Compared to fixed beds, fluid beds exhibit fairly high carryover of combustible solids that must be recovered and recycled to the gasifier or utilized in some other fashion. Removal of ash from a fluid bed, without loss of fuel, is also a difficult task. Tar formation may or may not be a problem, depending on the fuel and the operating conditions. Finally, experience with fluid-bed gasifiers now being developed for various high-Btu gasification processes has shown that coals with free-swelling indices greater than 2 generally cannot be processed without pretreatment or dilution with inert solids.

### 3. Entrained-flow gasifiers

Entrained-flow gasifiers can utilize virtually any grade of coal. Unlike fixed-bed and fluid-bed units, no tars are produced since entrained-flow gasifiers are ideally operated at high temperatures (in the slagging region). The overall gas production rate per unit volume of an entrained-flow system is substantially higher than for fluid-bed or fixed-bed gasifiers.

The major drawback of entrained-flow gasifiers is due to the high gas-flow rates and short residence times of particles in the reactor. Since part of the coal charged is carried out of the reaction space, it must be mechanically recovered and recycled to improve carbon conversion. Because of high exit-gas temperatures (2,500°-3,000° F), heat recovery is imperative; however, heat recovery, as well as solid collection, may be complicated by the presence of molten ash particles in the exit gas stream.

## B. Commerical Coal Gasifiers

### 1. Koppers-Totzek

The Koppers-Totzek is an entrained-flow type gasifier marketed by the Koppers Co., Inc., of Pittsburgh. Gasification is carried out at high temperature using oxygen and steam, and about 50 percent of the coal ash exits the gasifier as molten slag. Operation is essentially at atmospheric pressure or slightly above.

Units have been built with outputs ranging from 36 million Btu/hr to 234 million Btu/hr; larger units, with outputs of 500 million Btu/hr, are under construction. Turndown capability is about 80 percent of maximum output.

The first commercial Koppers-Totzek was constructed in 1952. Since then, 48 units have been built or are under construction in various parts of the world largely for production of synthesis gas for ammonia manufacture.

### 2. Lurgi

The American Lurgi Corporation (New York) markets a fixed-bed gasifier that operates at pressures ranging from 20 to 30 atmospheres. Maximum output of a 12-ft diameter unit (largest size made) is about 230 million Btu/hr with a turndown capability of 50 percent. The gasification agent may be either air-steam or oxygen-steam. Ash is removed through a revolving grate at the bottom of the unit.

The first commercial installation of Lurgi gasifiers was in Germany in 1936. Since then, 58 units have been built to supply town gas and synthesis gas.

### 3. Wellman-Galusha

McDowell-Wellman Engineering Company of Cleveland produces Wellman-Galusha fixed-bed gasifiers. Unit sizes range from 6.5 ft in diameter to 10 ft in diameter. Maximum gas production rates of 75 million Btu/hr are possible in an agitator-equipped 10-ft unit; a turndown capability of 7 percent of maximum output is claimed.

Operation of the Wellman-Galusha is similar to that of a Lurgi except that the former is an atmospheric pressure unit. Like the Lurgi, air-steam or oxygen-steam may be used.

The first commercial agitator-type Wellman-Galusha was built in this country in 1952. There are several plants in the United States presently operating such units or keeping them on standby in the event of natural gas cutbacks.

### 4. Winkler

The Winkler is an atmospheric pressure, fluid-bed gasifier marketed by Davy Power Gas, Inc., of Lakeland, Florida. Units have been built ranging from 3 to 18 ft in diameter. Maximum output from an 18-ft unit is about 500 million Btu/hr of fuel gas, with a turndown of 50 percent. Either air-steam or oxygen-steam may be used as the gasification agent.

The first commercial Winkler gasifier was built in Germany in 1926 and since then, 36 units have been constructed in various locations throughout the world.

### 5. Riley Morgan

The Riley Stoker Co. (Worcester, Massachusetts) is developing a modified version (equipped with a stirrer) of the Morgan fixed-bed producer that was widely used natural gas. Most such processes involve some type of liquid sorption, followed by regeneration of the sorbent to release $H_2S$ for conversion to elemental sulfur in a Claus plant.

Many of these processes are not selective for $H_2S$ but also remove substantial amounts of $CO_2$, which is not necessary, and which may not be desirable since this increases the required sorbent flow rates. Large amounts of $CO_2$ in the off-gas may also complicate Claus plant operation. In addition, some of the processes operate at below ambient temperatures, which would require further cooling of the fuel gas. Others operate at elevated pressures, which would require compression of the fuel gas.

A brief description of a number of commercial processes that should be considered for fuel gas desulfurization is given below.

1. Amine Scrubbing Processes

Processes based on scrubbing with various types of amine solutions have been used for several decades. Modern versions include the Sulfinol, Alkazid, Sulfiban, and Econamine processes. Main application of amine scrubbing has been for sweetening of sour natural gases and treatment of refinery gases.

All of the amine processes remove, in addition to $H_2S$, varying amounts of $CO_2$. Temperature of operation ranges from ambient to about 100° F. The acid gases react chemically with the sorbent to form loosely bound salts. The spent sorbent is usually regenerated by pressure reduction, and steam heating in a stripping vessel.

2. Physical Absorption Processes

Physical absorption processes were developed primarily to purify synthesis gases made by gasifying various fuels, including coal. Examples of commercial processes presently in use and the absorbent employed are: Rectisol (methanol), Purisol (N-methyl-2-pyrrolidone), Selexol (dimethyl ether polyethylene glycol), and Fluor (propylene carbonate).

These processes remove both $H_2S$ and $CO_2$ and, in some cases, $NH_3$, HCN, COS, tars, and higher hydrocarbons. All operate at temperatures near ambient or below. Regeneration of spent sorbent consists of depressurization and heating.

3. Alkali Scrubbing Processes

Alkali scrubbing processes involve chemical reactions between acid gases and various alkaline salts dissolved in water.

The Benfield and Catacarb processes employ potassium carbonate in solution with a catalyst and can operate at temperatures up to 250° F. Both processes remove large amounts of $CO_2$ in addition to $H_2S$. They operate best at elevated pressures (ca. 300 psig), and regeneration consists of pressure reduction and heating.

The Shell hot $K_3PO_4$ process can also operate at temperatures up to 250° F. $K_3PO_4$ is more soluble in water than $K_2CO_3$ resulting in lower liquor flow rates. However, large amounts of steam are still required for regeneration of sorbent.

The Vacuum Carbonate process employs $Na_2CO_3$ and is similar to the now obsolete Seaboard process. Regeneration consists of heating under a vacuum of about 26 in. Hg.

4. Direct Oxidation to Elemental Sulfur

Direct oxidation processes convert $H_2S$ removed from the gas stream directly to elemental sulfur without the need for a Claus plant; they are selective for $H_2S$—a desirable characteristic. Commercially available systems include the Stretford, Giammarco-Vetrocoke, and Takahax processes.

The Stretford process operates over a wide range of pressures and in a temperature range of 50°-100° F. Applications have included treatment of town gas (from petroleum), coke-oven gas, and producer gas.

The process consists of scrubbing the gas with an alkaline solution containing a vanadium salt along with anthraquinone-disulfonic acid (ADA). $H_2S$ is converted to elemental sulfur by the vanadic salt, which itself is reduced to the vanadous form. The reduced liquor is fed to oxidizers where the vanadium is restored to its vanadic form via a redox mechanism with ADA. Air is blown through the liquor to reoxidize the ADA and elemental sulfur is separated by froth flotation. The froth is either filtered or centrifuged, washed, and melted to produce high-quality sulfur. Systems are available, if necessary, to provide pretreatment of the raw fuel gas to remove troublesome impurities, as well as purify the scrubbing liquor.

The Giammarco-Vetrocoke process employs a scrubbing solution of sodium arsenates and arsenites. Absorption of $H_2S$ occurs at temperatures in the range of 60°-212° F and at pressures ranging from atmospheric to 15 atm. Regeneration of sorbent takes place in an air-blown oxidizing column at 100° F and atmospheric pressure, simultaneously producing elemental sulfur.

The Takahax process has been employed exclusively in Japan for treatment of coke oven gas, chemical plant waste gases, and sewage fermentation gases. The absorbing solution contains sodium, 1,4-naphthaquinone, 2-sulfonate as catalyst, and sodium carbonate. Absorbed $H_2S$, in the form of sodium bisulfide, is oxidized by the catalyst to precipitate elemental sulfur. The solution is regenerated by contacting with air. Both absorption and regeneration occur under ambient conditions.

*Economics of Coal Gasification*

A detailed discussion of the costs involved in producing a clean fuel gas from coal is beyond the scope of this paper. To the authors' knowledge, no independent prior to 1980. Two unit sizes of 12 ft and 16 ft in diameter will be offered; predicted output of the larger unit is about 350 million Btu/hr, when oxygen-blown. Maximum operating pressure will be 40 inches of water. Present company plans call for extensive testing of a prototype prior to marketing.

6. Kellogg

The Kellogg Co. (Houston) is prepared to market a stirred, fixed-bed gasifier that operates at pressures ranging from 10 to 20 psig; it is otherwise similar to a Wellman-Galusha. Unit sizes range from 8 ft to 12 ft in diameter. Maximum output of the largest unit is about 100 million Btu/hr with a turndown to 25 percent. The gasifier may be either air-blown or oxygen-blown.

7. Wilputte

The Wilputte Corp. of Murray Hill, N.J., is offering a version of the Chapman gas producer that was once popular in the United States. Several such units are still operating at a site in eastern Tennessee.

The Wilputte is an atmospheric-pressure, fixed-bed gasifier with a maximum internal diameter of 10 ft 4 in. The unit is equipped with a rotating grate for ash discharge, and a rotating rabble arm to break up coal agglomerates at the top of the bed. Maximum output of an air-blown unit is about 25 million Btu/hr. Oxygen may also be used.

8. Woodall-Duckham/Gas Integral

The WD/GI gasifier is a two-stage fixed-bed unit offered by Woodall-Duckham (U.S.A.) Ltd. of Pittsburgh. Coal is distilled in a retort section, driving off water vapor, oil and tar, and volatiles. Offtake temperature of the gas from this section is about 250° F. The gas (referred to as top gas) is treated downstream to remove tar and oil.

Coke produced in the retort is gasified in a lower section as in conventional single-stage gasifiers. Gas produced in the lower section (clear gas) exits at 1,200° F, passes through a cyclone, and is combined with the top gas, resulting in a mixture of raw fuel gas at 700° F.

Maximum output from a standard 12-ft-diameter unit is about 80 million Btu/hr. A turndown to 25 percent of maximum is possible. WD/GI gasifiers have been in service for over 30 years in Europe, South Africa, and Australia. Approximately 100 units have been constructed.

9. Applied Technology

Both a single-stage and a two-stage gasifier are available through Applied Technology Corp. of Pittsburgh. Applied Technology is under license to the British firm Wellman-Incandescent, Ltd.

The two-stage system is very similar to the WD/GI gasifier described above. The single-stage unit is equipped with an eccentric revolving grate for ash discharge, but has no stirring device. The generator sections of both types are identical. Unit sizes range from 4.5 to 12 ft in diameter. The output of 12-ft-diameter units is claimed to be 87 million Btu/hr. Twenty-two units have been built in South Africa since 1964. Four more are presently under construction.

### *Fuel Gas Cleanup*

Regardless of the process used to make fuel gas from coal, it is likely that the gas will have to be cleaned to meet environmental standards, end-use requirements, or both. The major impurities present in these gases will be hydrogen sulfide, particulates, and in the case of fixed-bed processes, possibly condensable tars and oils.

Compared to stack gas scrubbing to remove sulfur dioxide from the products of complete combustion, there are several advantages in desulfurizing raw, coal-derived fuel gas. The sulfur compounds, mainly hydrogen sulfide, are present in higher concentrations—the gas has not been diluted with the final combustion air. The volume of gas to be treated is only a fraction of the volume of the final combustion products; hence, smaller equipment sizes can be used. Finally well-proven technology exists for removal of $H_2S$ from gases as compared to $SO_2$ stack gas processes, which are still experiencing technical difficulties.

All commercially available sulfur removal systems operate at temperatures below about 250° F. Off-gas temperatures from fixed-bed gasifiers are generally in the range of 800°-1,200° F, and may be much higher for fluid-bed or entrained-flow gasifiers. Thus, the gas will have to be cooled substantially prior to final cleanup. This can be accomplished in a waste-heat boiler. The steam so generated can be added to the distribution mains of the industrial complex, or used, in part, in the gasification process.

In some cases, the raw fuel gas will contain tars and oils that will begin to condense from the gas in the waste heat recovery system. Tars removed at this point could possibly be reinjected into the gasifier, burned as boiler fuel, or sold as a byproduct.

Gas temperature after heat recovery will be in the neighborhood of 350°-400° F. The gas can be cooled further by water scrubbing, which will remove any remaining tar and particulates. Venturi scrubbers will provide more than adequate separation of such impurities. Water used for scrubbing will be filtered (to remove condensed tars and particulates), cooled, and recirculated to the scrubber.

Sulfur in the raw fuel gas will be present chiefly as hydrogen sulfide. Numerous processes have been developed for removing $H_2S$ from various gases including coke oven gas, refinery gas, synthesis gas, and sour analysis of the various commercial processes has, as yet, been published.

Inasmuch as estimates of capital and operating costs reported by manufacturers are not on a common basis, reporting of specific figures here without detailed explanation would be unfair, and perhaps meaningless. However, to give an approximate indication of costs involved, the ranges of important cost factors as given in the manufacturers' recent literature are discussed.

Installed costs for gasification equipment, excluding sulfur removal, range from $6,000 to $23,000 per $10^6$ Btu/hr of fuel gas, with an average of $15,300. These figures, in some cases, include particulate removal and/or integral waste heat boilers. Installed costs, including desulfurization equipment, range from $36,000-$61,000 per $10^6$ Btu/hr, with an average of $45,200. The investment in sulfur removal equipment would, therefore, easily be the largest cost associated with a coal gasification facility.

Manufacturers' estimates of operating costs are given in terms of dollars/$10^6$ Btu of fuel gas. However, these figures are highly sensitive to the values assumed for coal prices.

To obtain a somewhat clearer comparison, production costs were converted to incremental costs per $10^6$ Btu of fuel gas, relative to the cost of the coal gasified. On this basis, incremental costs of clean fuel gas ranged from $1.10 to $1.51 per $10^6$ Btu, with an average of $1.24. Thus, for coal costing $30 per ton (12,500 Btu/lb), this would result in a clean fuel gas cost of about $2.44 per $10^6$ Btu.

No attempt has been made here to distinguish between process costs based solely on air-steam gasification or solely on oxygen-steam gasification. Suffice it to say that the costs for producing either a desulfurized low-Btu gas or a medium-Btu gas fall within the ranges quoted above. It is not apparent from the available data as to which fuel could be produced more cheaply.

While the initial reaction may be that the use of oxygen in a gasification system would lead to higher production costs, the opposite may be true in certain situations. While the investment in an onsite oxygen plant is significant, power requirements for driving the compressors may be met, in whole or in part, by use of waste heat from the gasifier. Use of oxygen in place of air should increase the maximum throughput of a given gasifier by 50 to 100 percent; hence, smaller, or fewer, gasifiers are needed for a given fuel requirement. Likewise, smaller desulfurization equipment is necessary. Finally, the cost savings to be realized in *utilizing* the higher quality medium-Btu gas, rather than low-Btu gas, may significantly shift the economics in favor of an oxygen-based system (see ***Properties of Coal-Derived Fuel Gases***, and of C.).

## ***Properties of Coal-Derived Fuel Gases***

### A. Chemical Composition

The chemical compositions of a number of different fuel gases manufactured from various coals (and coke) are given in table 2. These gases were produced by various commercial gasifiers operating at near-atmospheric pressure. Since a purpose of this study was to draw some ***general*** conclusions about combustion properties of coal-derived fuels, the gases indicated were selected at random from data reported in the literature.

The main combustible constituents in these gases, CO and $H_2$, result from the chemical reactions[2] involved in the gasification process:

$$C + O_2 = CO_2 \tag{1}$$

$$C + CO_2 = 2CO \tag{2}$$

$$C + H_2O = CO + H_2 \tag{3}$$

$$CO + H_2O = CO_2 + H_2 . \tag{4}$$

Reaction (1) is exothermic and supplies the heat necessary for the actual gasification reactions (2) and (3), which are endothermic. Reaction (4) is the so-called water gas shift reaction.

The trace amounts of methane found in these gases probably result from devolatilization of the coal. Production of methane by other chemical reactions is generally insignificant at low pressures.

The heating values of the fuel gases are related to the amount of nitrogen in the gases; the latter is, in turn, related to the degree of oxygen enrichment of the gasifying agent. The data plotted in figure 2 (taken from ref. 11) show that there is a fairly uniform increase in fuel heating value, with increasing oxygen level in the oxidant stream.

The presence of fairly large amounts of carbon monoxide in coal-derived gases probably makes these fuels undesirable for residential or commercial use. However, industry has had considerable experience in the handling of toxic gases; hence, the use of a CO-rich fuel should present no special problems.

### B. Material Flows Involved in Combustion of Coal-Derived Fuel Gases

The quantities of fuel, air, and combustion products involved in the combustion of coal-derived gases were evaluated. All computations were based on the assumption that the various fuels are burned with their stoichiometric amounts of air, of the following composition:

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[2] A more detailed discussion is given in reference 10.

| | Percent |
|---|---|
| $N_2$ | 77.10 |
| $O_2$ | 20.69 |
| $CO_2$ | 0.03 |
| Ar | 0.92 |
| $H_2O$ | 1.26 |

It is of interest to compare the values calculated for the coal-derived fuels with the corresponding quantities for methane, carbon monoxide, and hydrogen. Hence, data for these latter three fuels, for the case of stoichiometric combustion, are given in table 3. For all intents and purposes, methane may be assumed to be equivalent to natural gas.

The relationship between fuel heating value and volume of fuel required per million Btu is shown in figure 3. This relationship is purely mathematical in nature, and is given by

$$\text{SCF fuel} = 10^6/\text{HHV}. \qquad (5)$$

Thus, in order to maintain a given thermal input to a process, approximately three times as much medium-Btu gas (ca. 300 Btu/SCF) as natural gas is required; for a low-Btu gas (ca. 150 Btu/SCF), the ratio increases to more than six.

The increased fuel flow rate required for low- and medium-Btu gases has serious implications when retrofitting of existing installations is considered. Since pressure losses in piping and equipment are approximately proportional to the square of the fluid velocity, it is readily seen that losses incurred in utilizing the coal-derived gases in an existing system can be substantial.

Problems associated with distribution of the fuel might be overcome by either enlarging the fuel mains or pressurizing the system. To maintain similar velocities in mains presently delivering natural gas at a given pressure, an increase in diameter by a factor of about 1.8 would be necessary for medium-Btu gas; for low-Btu gas, the factor is about 2.6. Such increases in duct size might not be feasible in certain installations because of space limi-

Table 2. Fuel gases produced by steam/air, steam/enriched air, or steam/oxygen gasification of coal and coke

| Fuel Gas No. | Percent by volume: CO | $H_2$ | $CH_4$ | $CO_2$ | $N_2$ | $O_2$ | Heating value[a] (HHV) Btu/SCF |
|---|---|---|---|---|---|---|---|
| 1 | 22.0 | 14.0 | 1.0 | 7.0 | 56.0 | 0.0 | 126.1 |
| 2 | 31.0 | 9.3 | 0.7 | 3.6 | 55.4 | 0.0 | 136.7 |
| 3 | 37.8 | 11.3 | 0.4 | 10.8 | 39.5 | 0.2 | 162.0 |
| 4 | 28.6 | 15.0 | 2.7 | 3.4 | 50.3 | 0.0 | 167.7 |
| 5 | 44.6 | 22.6 | 0.4 | 10.8 | 21.0 | 0.6 | 220.5 |
| 6 | 48.8 | 29.1 | 0.4 | 12.0 | 9.0 | 0.8 | 255.0 |
| 7 | 53.3 | 30.9 | 0.4 | 12.8 | 2.3 | 0.3 | 275.3 |
| 8 | 48.2 | 35.3 | 1.8 | 13.0 | 0.9 | 0.8 | 287.1 |
| 9 | 56.6 | 37.3 | 0.0 | 5.0 | 1.1 | 0.0 | 302.7 |

[a] SCF at 60° F, 1.0 atm.

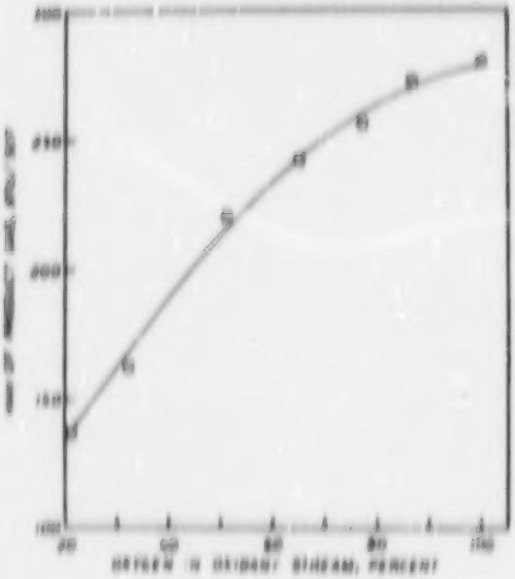

Figure 2. Effect of oxygen level on heating value of product gas (gasification of coke).

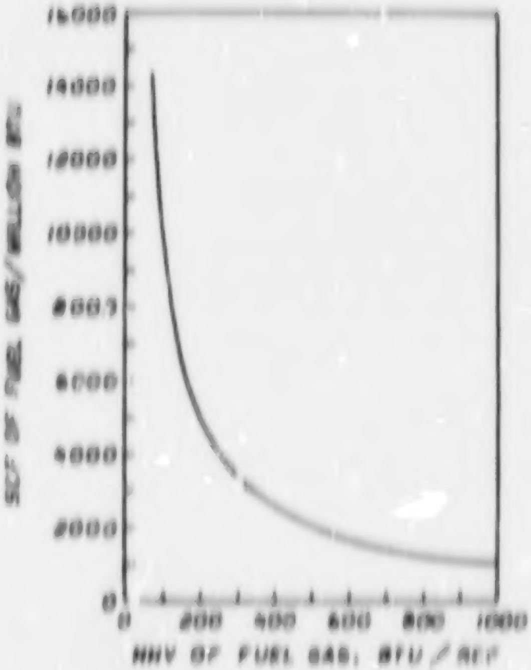

Figure 3. Volume of fuel per million Btu vs. heating value of fuel gas.

Table 3. Stoichiometric combustion data from CO, $H_2$, and $CH_4$

| Fuel | Heating Value (HHV) Btu/SCF | SCF Air/ SCF Fuel | SCF/million Btu Fuel | SCF/million Btu Air | SCF/million Btu Comb. prod. |
|---|---|---|---|---|---|
| CO | 321 | 2.42 | 3115 | 7527 | 9279 |
| $H_2$ | 324 | 2.42 | 3084 | 7463 | 9090 |
| $CH_4$ | 1010 | 9.67 | 990 | 9570 | 10560 |

tations. Use of pressurized mains could solve this problem, but may not be desirable because of safety considerations.

Use of low-Btu gas in burners originally designed for natural gas (and/or oil) is probably not possible. It has been reported, however, that a medium-Btu fuel could be burned in utility boilers with only minor modifications to the existing equipment (ref. 12).

An analysis of problems associated with combustion of coal-derived gases using various conventional industrial burners is given in reference 18. The overall conclusion of the authors was that there should be no difficulty in burning medium-Btu gases. However, flame stability problems may be encountered in combustion of low-Btu gases.

In the past, a number of different types of burners have been successfully used to burn low-Btu gas (refs. 7,8). Undoubtedly, such burners can be improved to meet modern standards. Again, the real problem is one of space limitations that may occur in existing systems; room may not be available to accomodate the larger burner diameters necessary for low-Btu gas firing at a desired thermal input.

The relationship between fuel heating value and volume of air required for stoichiometric combustion of coal-derived gases is given in figure 4. It may be seen that a linear correlation exists; the data were fitted by least squares to obtain the expression

$$\text{SCF AIR/SCF FUEL} = 7.35 \times 10^{-3}\ \text{HHV} + 0.035 \quad (6)$$

An expression relating the volume of air per million Btu of fuel fired is obtained by simply combining equations (5) and (6):

$$\text{SCF AIR}/10^6\ \text{Btu} = 7{,}350 + 35{,}000/\text{HHV} \quad (7)$$

Equation (7) is plotted in figure 5 along with the data pertaining to the various fuel gases given in table 2.

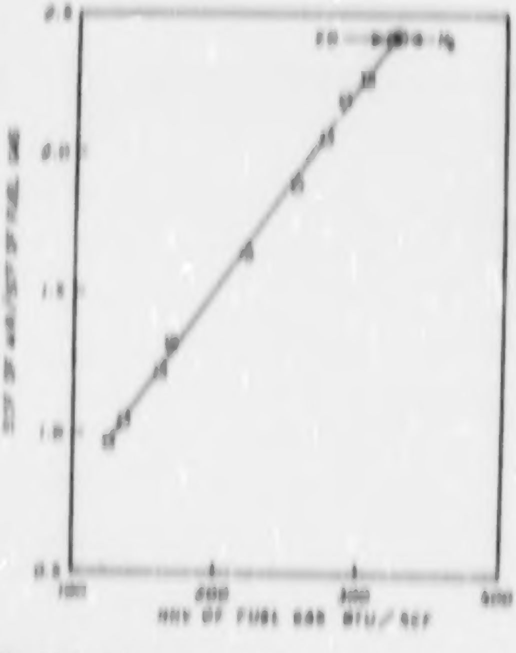

**Figure 4. Volume of air required to burn 1 ft$^3$ of fuel gas vs. heating value of fuel gas, 100 percent stoichiometric air.**

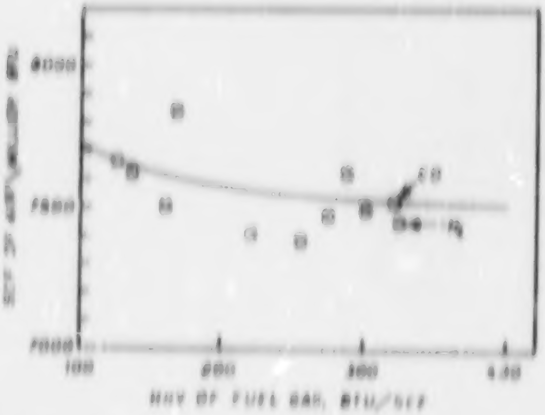

**Figure 5. Volume of air per million Btu of fuel vs. heating value of fuel gas, 100 percent stoichiometric air.**

Figure 5 indicates that, for all of the gases considered, the air requirements per million Btu of fuel fall in the range of 7,400 to 7,800 SCF. Since the air required for burning a million Btu of natural gas is about 9,000 SCF, no problems are anticipated in regard to air supply when substituting a coal-derived gas for natural gas in an existing system.

The variation in volume of combustion products resulting from burning different fuel gases is depicted in figure 6. Volumes associated with low-Btu gases below 200 Btu/SCF are substantially greater than that resulting from natural gas ($CH_4$) combustion. This is due largely to the much greater quantities of *fuel* required when burning the low heating-value gases as compared to natural gas; as was pointed out, the *air* requirement is actually less for the coal-derived gases.

The increased flow of combustion products from the low-Btu gases causes retrofit problems similar to those enumerated earlier regarding fuel flow rates. In existing installations, there will be greater velocities and draft losses than when burning natural gas at a given firing rate. For gases above about 200 Btu/SCF, there appears to be no problem.

As the heating value of the fuel gas decreases, the ratio of the amount of combustion products to the amount of combustion air increases. This has implications in regard to downstream heat recovery if only air preheating is employed; the incoming air can only absorb a fraction of the sensible heat of the combustion products and, hence, overall process efficiency suffers. A much larger percentage of the energy in the flue gas can be recovered if both air and fuel are preheated, and this

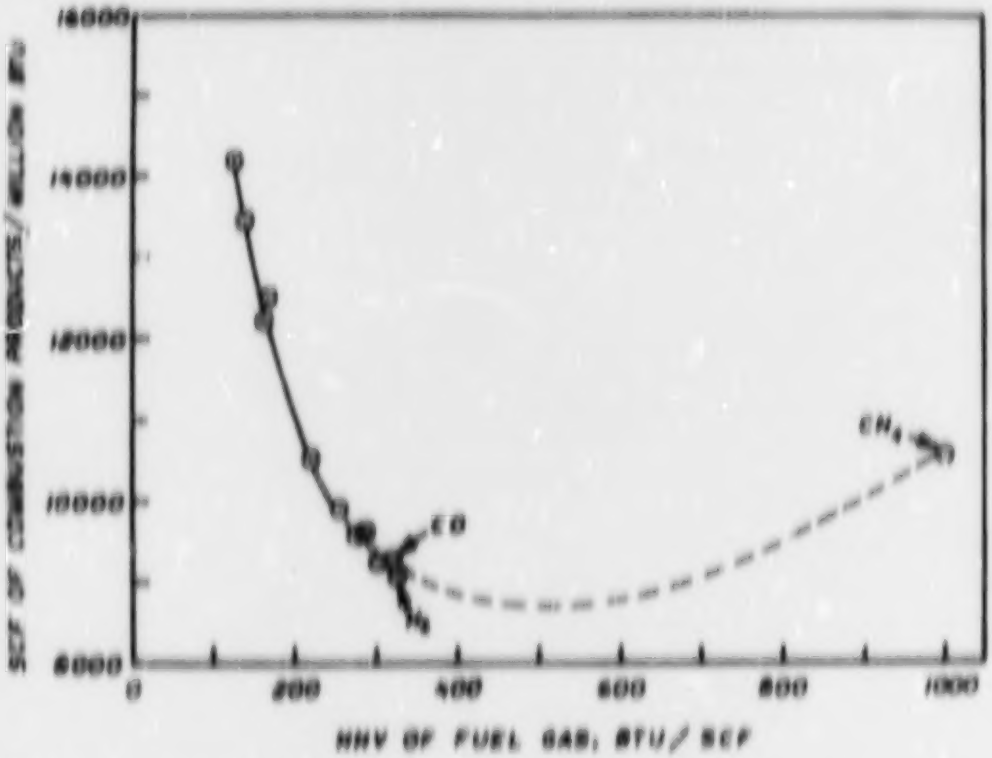

Figure 6. Volume of combustion products per million Btu of fuel vs. heating value of fuel gas, 100 percent stoichiometric air.

can be done in suitably designed systems. However, the (actual) volume increase due to heating of the fuel may exacerbate problems related to fuel flow to the burners.

C. Combustion and Heat Transfer Properties

An evaluation of several quantities related to the combustion and heat transfer characteristics of the fuel gases listed in table 2 was conducted. In some cases, all of the gases were considered. In other cases, only selected examples were analyzed.

Figure 7 shows the relationship between the calculated adiabatic flame temperature of the fuel gases and their heating values. For the purposes of these computations, it was assumed that each of the gases was burned with its stoichiometric amount of air, with both fuel and air initially at 77° F (298.15 K). The calculations were carried out using the PERC Multiphase Chemical Equilibrium Program developed at the Pittsburgh Energy Research Center (ref. 13).[1]

The nearly linear relationship between flame temperature and heating value is not surprising. The main combustible constituents in these gases are $H_2$ and CO, which exhibit nearly identical heating values and flame temperatures. As we go from low- to medium-Btu gases, we are simply approaching a mixture of $H_2$ and CO.

The data presented in figure 7 were fitted by least squares, yielding the expression:

$$T_{flame} = 4.20\ HHV + 2,464 \qquad (6)$$

This equation should provide a reasonable first approximation to the flame temperature of any coal-derived gas ranging in heating value from 100 to 300 Btu/SCF, provided that the $CH_4$ content is not much greater than the percentages indicated in table 2.

It should be noted that the flame temperature for natural gas ($CH_4$), with a heating value of 1,010 Btu/SCF, is 3,617° F. This is some 200° F below that calculated for fuel no. 8, table 2, with a heating value of about 303 Btu/SCF. The reason for this apparently anomalous situation is that it requires a considerably

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[1] The authors acknowledge the aid of Francis E. Spencer and James G. Hendrie of the Energy Conversion section, Pittsburgh Energy Research Center, in making these computations.

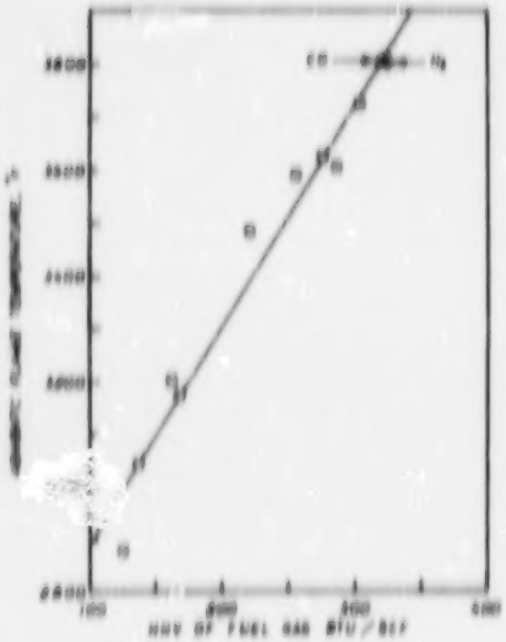

Figure 7. Adiabatic flame temperatures of coal-derived fuel gases, 100 percent stoichiometric air.

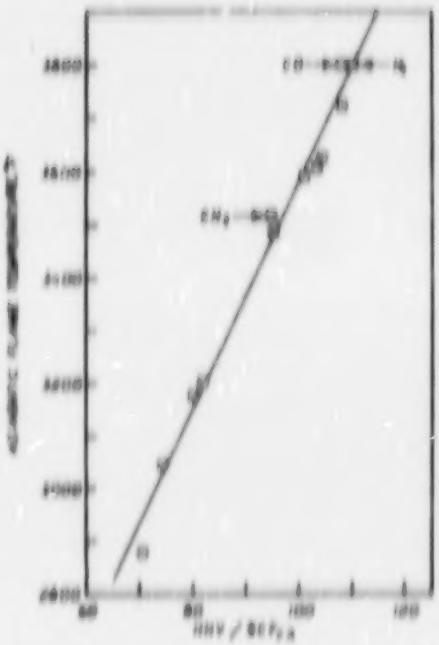

Figure 8. Adiabatic flame temperatures of fuel gases vs. heat releases per unit volume of combustion products (Scf$_{c.p.}$ = vol. of comb. prod./vol. of fuel, 100 percent stoichiometric air.

greater amount of air to burn natural gas (9.7 SCF air/SCF fuel) than it does medium-Btu gas (2.3 SCF air/SCF fuel). As a consequence, the heat release per unit volume of combustion products is less in the case of natural gas than for the medium-Btu gas, resulting in a lower flame temperature for the former. This relationship, shown graphically in figure 8, is described by the equation:

$$T_{flame} = 21.58\,(HHV/SCF_{c.p.}) + 1,420 \qquad (9)$$

where SCF$_{c.p.}$ is the volume of combustion products per unit volume of fuel. Equation (9) is more general and somewhat more accurate than equation (8), although less convenient to use.

In figure 9 are plotted the so-called "heat availability" curves (ref. 3) for a medium-Btu gas (303 Btu/SCF), a low-Btu gas (168 Btu/SCF), methane, and No. 2 fuel oil. These curves simply reflect the fraction of gross thermal input to a process that is available for heat transfer when the flue gas exit temperature is as specified on the abscissa.

It may be noted that the curve for a given fuel intersects the abscissa at the adiabatic flame temperature of the fuel. In effect, this simply says that if the products of combustion of a particular fuel leave a furnace at the adiabatic flame temperature, no heat has been transferred and the heat availability is zero.

As the flue gas temperature decreases, the available heats of the various fuels approach each other. Thus, in applications with low flue gas temperatures, such as boiler firing, any of these fuels can be utilized quite efficiently in a properly designed unit.

In many industrial operations, however, high flue gas temperatures, in excess of 2,000° F, are encountered. Frequently, no heat recovery is employed. In these cases, the available heat curves give a direct indication of the process efficiency. In fact, they represent the maximum process efficiency possible when there are no heat losses from the system.

Taking as an example a situation where the flue gas temperature is maintained at 2,000° F, we see that the process efficiencies range from about 40 percent for low-Btu gas to about 53 percent for medium-Btu gas; an efficiency of 46 percent is achieved when burning methane.

The significance of these figures is that, for a given

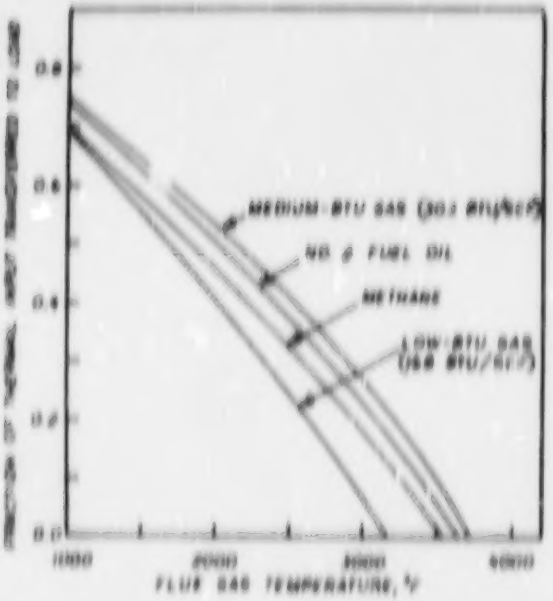

Figure 9. Available heat vs. flue gas temperature, 100 percent stoichiometric air.

heat transfer to the load and the same exit temperature of 2,000° F, about 16 percent more Btu of natural gas are required than of medium-Btu gas. Under the same conditions, about 33 percent more Btu's of low-Btu gas are needed. For a flue gas temperature of 2,500° F, 26 percent more methane and 64 percent more low-Btu gas are required than medium-Btu gas.

The above analysis considers only the thermodynamics of the heat transfer process, and offers no insight regarding the actual rates of heat transfer involved. In order to gain such insight, the rates of heat transfer achieved when burning various fuels under idealized conditions were evaluated. The conditions selected were as follows: (1) all fuels were burned with their stoichiometric amounts of air, with no preheat of either air or fuel; (2) combustion took place in a well stirred, cubical furnace bounded on all sides by a black surface maintained at 1,000° F; (3) the size of the furnace was such that nonluminous radiation was the major mode of heat transfer, convective heat transfer being negligible (a mean beam length of 10.0 ft was chosen, which corresponds to an actual furnace size of about 17.5 ft on a side); (4) there were no heat losses from the system.

Emissivities and absorptivities were evaluated using the methods described in reference 14. The emissivities corresponding to several different coal-derived gases and methane are displayed in figure 10 as a function of temperature. It should be noted that the values of emissivity associated with the low-Btu gases are substantially less than those for methane combustion products. On the other hand, the emissivity curves for the medium-Btu gases fall quite close to that for methane.

The values of absorptivity were found to fall in the range 0.4-0.5 in all cases considered and were a weak function of temperature. Hence, the absorptivities had only a minor affect on the calculated heat transfer rates.

Figure 11 depicts the efficiency of radiant heat transfer as a function of furnace load for a low-Btu gas, a medium-Btu gas, methane, and No. 2 fuel oil. This plot is analogous to the plot of available heat curves (figure 9) discussed previously, but with one principal difference. In order to achieve a given heat transfer rate in the idealized furnace, it is necessary for gases with low emissivity to maintain a higher temperature in the furnace than for gases with high emissivity. As a result, the lesser radiating gases exit the furnace at a higher temperature and their utilization efficiency declines.

In comparing figure 11 with figure 9, one sees that the relative positions of the methane and medium-Btu gas curves remain essentially unchanged because of the similar emissivities involved in the calculations. The

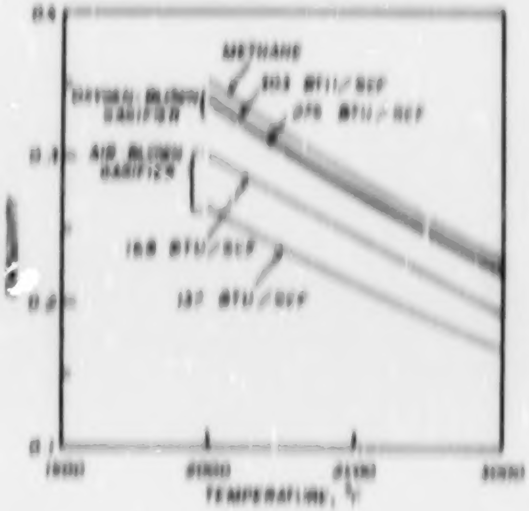

Figure 10. Emissivities of combustion products of coal-derived fuel gases and methane. Pressure = 1.0 atm; mean beam light = 10.0 ft. 100 percent stoichiometric air.

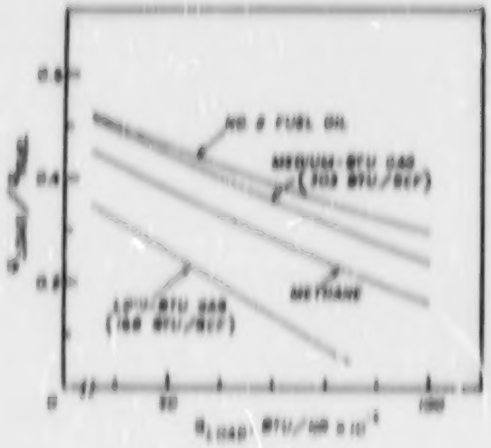

Figure 11. Efficiency of radiant heat transfer vs. thermal load, 100 percent stoichiometric air.

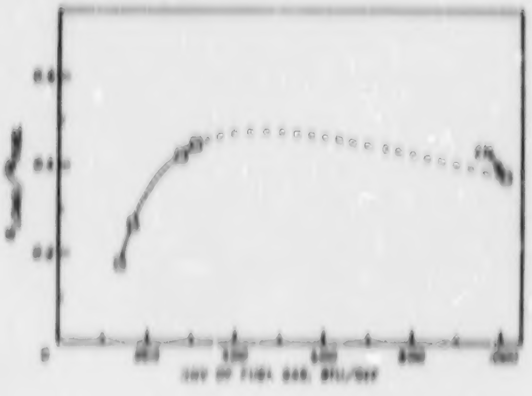

Figure 12. Efficiency of radiant heat transfer vs. heating value of fuel gas, 100 percent stoichiometric air $Q_{LOAD} = 50 \times 10^6$ Btu/hr.

curve for No. 2 oil is now higher than the rest because the emissivities used were corrected to allow for luminosity, as suggested by reference 15.

The curve for the low-Btu gas, however, now falls substantially lower than the others. This is a direct result of the much lower emissivities associated with combustion of this fuel. To maintain a heat transfer rate of 65 x $10^6$ Btu/hr (about midrange in figure 11), it would be necessary to use 227 percent more Btu of low-Btu gas than of medium-Btu gas.

Figure 12 shows the general trend in utilization efficiency of various gaseous fuels as a function of fuel heating value, at fixed furnace load. While the region between 300 and 1,000 Btu/SCF was not examined, the broken line is probably a fair representation of the actual situation. The curve shows clearly that, for the case considered here, a medium-Btu gas of about 300 Btu/SCF is nearly the optimal gaseous fuel in terms of heat transfer properties. This figure also indicates that a coal-derived fuel gas of about 220 Btu/SCF would exhibit heat transfer characteristics identical to those of natural gas. In view of figure 8, such a fuel could be manufactured using enriched air containing about 50 percent oxygen; this is equivalent to an oxygen/air ratio of 0.6 SCF $O_2$/SCF air.

The principal conclusions to be drawn from this analysis are: (1) coal-derived fuel gases with heating values in the range 200 to 300 Btu/SCF should provide utilization efficiencies equal to, or better than, that of natural gas; (2) the heat-transfer properties of gases below about 200 Btu/SCF are such that for some applications it may be more economical, in terms of greatly reduced fuel consumption, to use a medium-Btu gas; this would appear to be particularly true in high-temperature processes that do not employ heat recovery.

### *Discussion*

It appears, from the preceding analysis, that a clean fuel, suitable for industrial use, can be manufactured from coal using existing, well-proven technology. Medium-Btu gases, made with oxygen or oxygen-enriched air, should exhibit combustion and heat-transfer properties equivalent to or better than those of natural gas; their use in existing facilities would require relatively minor modifications of equipment. Low-Btu gases, resulting from steam/air gasification of coal, could also be used, but somewhat less effectively; more extensive modifications of existing equipment would be necessary. In a properly designed system, however, even the low-Btu fuels would provide satisfactory performance.

A question remains concerning the optimum approach to utilizing coal gasification technology. A large company may find it advantageous to construct its own gasification/cleanup facility for onsite use. The byproducts of gasification—steam, and possibly oxygen and nitrogen used in the process (and often needed in manufacturing operations)—could be absorbed by the operator or sold to nearby plants.

A very attractive arrangement would be an industrial park served by a central gasification facility. Fuel gas, process steam, and steam for space heating could be distributed to a number of closely situated plants. Cost of the operation would then be shared by the resident industries.

It appears that medium-Btu gases can be transmitted economically over considerable distances (refs. 18,19,20). This presents the possibility of a mine-mouth gasification plant distributing fuel gas to industries within a radius of perhaps 50 to 100 miles, much as merchant gas plants did in the past. Such an arrangement offers the economic advantages of large-scale operation.

It has been pointed out by Mitsak and Kamody (ref. 16) that if all of natural gas consumed by industry were displaced by an alternate fuel, the rate of discovery of new reserves (under *present* economic conditions) is almost sufficient to meet the needs of residential and commercial users. Assuming an annual population growth of 1.1 percent, the existing natural gas supply system would be adequate for about 80 years.

While total conversion of industry to coal-derived gases is probably not practicable, let us examine the situation if such were the case. Total annual consumption of natural gas by industry is roughly equivalent to about 550 million tons of coal coverted to low- and medium-Btu fuel gases. This is nearly equal to the amount of coal presently produced annually (600-650 million tons). It is believed, however, that doubling of the annual output of coal could be effected, with some difficulty, by 1985 (ref. 17).

The gasification hardware required in this hypothetical situation would probably amount to 2,000 to 12,000 units of present design, depending on the sizes utilized. It should be remembered that, at one time, 11,000 gasification units were in operation in the United States, although these were of smaller capacity and were without desulfurization facilities.

While the magnitudes of capital and resources involved in a total conversion of industry to coal-derived fuels appear immense, such a possibility is probably not beyond our national capability under the proper set of circumstances. The point to be made, however, is that, realistically, we have the technology and resources available to effect a *very substantial* displacement of natural gas from the industrial sector. The freeing of this fuel for more appropriate end uses could extend its use many decades beyond the point of extinction now predicted.

### *Conclusions*

Any industry, faced with curtailments in its supply of natural gas, would do well to seriously consider the use of coal-derived fuel gases. Such fuels can be manufactured using currently available technology.

Medium-Btu gases (~ 300 Btu/SCF) from coal could be substituted for natural gas in many applications without major changes in equipment. Low-Btu gases (ca. 150 Btu/SCF) could be effectively utilized in properly designed new installations.

The cost of coal-derived fuel gases will undoubtedly be greater than what American industry is accustomed to paying for natural gas and oil. However, cost may be of secondary importance when the choice is between a more expensive, readily available fuel or no fuel at all.

An early acceptance of coal gasification technology by industry could have a profound impact on our energy supply situation in the years ahead. Large amounts of natural gas would be freed solely for residential and commercial use, which could conceivably extend the availability of this fuel well into the next century.

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# THE EPA R&D PROGRAM IN WASTES-AS-FUEL: AN OVERVIEW FOCUSING ON PROCESS ENVIRONMENTAL/ENERGY IMPACTS

George L. Huffman*

***Abstract***

*The USEPA is conducting a broad-based program in research and development in the area of waste utilization as alternative fuel sources. Major waste-as-fuel technologies and methods are being explored to determine their environmental and energy impacts, and to develop technology to control undesirable environmental impacts. Major processes include: use of waste as a supplementary fuel in large pulverized-coal boilers, in other types of coal-fired boilers, in oil-fired boilers, and in industrial and smaller institutional boilers; direct conversion of wastes to electricity via a gas turbine; and the pyrolytic conversion of wastes to fuel gas and fuel oil. A description of these processes is presented, as is the status of those R&D projects which encompass them. The environmental aspects of these processes are summarized, along with projections of their energy conservation attributes.*

## INTRODUCTION

Solid waste is generated from most all activities: from the farm to the feedlot; from the home to businesses; from mineral extraction operations to all types of industrial manufacturing operations. The use of solid waste as a fuel for energy generation has been practiced for some time in Europe. Its practice in this country, however, is essentially just beginning. In the United States, numerous processes are under development which convert the energy contained in solid waste into steam, oil, gas, and electricity.

In this paper, the amount and availability of the heat and energy content of the Nation's combustible solid waste will be briefly discussed. A number of processes under EPA development to convert otherwise-polluting solid waste into usable energy forms will also be considered, along with a brief summary of the environmental characteristics of such conversion processes. The discussion will begin with a review of EPA's legislative authorities in the waste-as-fuel area, and will conclude with an overview of EPA's current environmental protection R&D program in the area.

## EPA'S LEGISLATIVE MANDATES IN WASTES-AS-FUEL

The administrator of EPA is mandated under the 1965 Solid Waste Disposal Act, as amended by the 1970 Resource Recovery Act (PL 91-512), to perform research and demonstrations to develop and to apply new and improved methods for processing and recovering both materials and energy from solid wastes. The act also requires the study of adverse health and welfare effects of the release into the environment of materials present in solid wastes, as well as methods of eliminating such effects. The act authorizes EPA to issue contracts and grants for research and/or demonstrations of technologies in the waste-as-fuel area to enable appropriate response to these mandates.

The administrator of EPA is mandated under the Clean Air Act and the Federal Water Pollution Control Act to establish performance standards for existing and new sources of pollution based on available technology. Also, specific provisions within each of these acts require the administrator to periodically review existing guidelines and revise information regarding best available control technologies, the costs of achieving standards, and other associated impacts. Under both acts, the administrator is charged with establishing a national research and development program for the prevention and control of pollution. The Clean Air Act authorizes EPA to do research on characterization of the air pollution problem associated with a new or existing source, such as a waste-conversion-to-fuel facility, and authorizes R&D on control technology aimed at lessening the environmental impact. The Federal Water Pollution Control Act and the Solid Waste Disposal Act authorize EPA to conduct R&D aimed at lessening the groundwater pollution potential associated with the disposal of solid wastes onto the land—wastes whose energy value is literally thrown away.

## WASTES AVAILABLE FOR FUEL RECOVERY: WHAT ENERGY IMPACT IS POSSIBLE

It has been estimated that about 4.6 billion tons (4.1 trillion kilograms) of municipal, industrial, mineral and agricultural solid wastes were produced in this country in 1970 (ref. 1). Of this amount, about 13 percent has been estimated to represent the dry, combustible fraction. Table 1 shows the detailed breakdown of this 13 percent that represents the country's dry, combustible solid waste stream. This table summarizes data presented in a 1972 report to the Environmental Protection Agency by the International Research and Technology Corporation (ref. 2). It shows that about 1,135 billion pounds (517 billion kilograms) or about 570 million tons of dry combustible solid waste were discarded in 1970 (refs. 2,3). By way of comparison, a Bureau of Mines estimate arrived at a figure of 880 million tons (800 billion kilograms) as the dry, organic waste genera-

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Table 1. Quantity and fuel value of dry combustible solid waste discarded in 1970 (refs. 2,3)

| Waste source | Combustibles discarded (billion of pounds) | | Fuel value in quadrillions of Btu's (Btu x $10^{15}$) | |
|---|---|---|---|---|
| Refuse and sewage--urban generated waste | | 275.5 | | 2.177 |
| Household and municipal | 168.4 | | 1.348 | |
| Sewage solids | 13.8 | | 0.083 | |
| Commercial and institutional | 62.1 | | 0.496 | |
| Manufacturing plant waste | 23.5 | | 0.188 | |
| Demolition | 7.7 | | 0.062 | |
| Manufacturing and processing waste | | 54.5 | | 0.436 |
| Wood related wastes (SIC 24xx - 27xx) | 51.3 | | 0.411 | |
| Textiles and fabric wastes (SIC 22xx - 23xx) | 0.6 | | 0.005 | |
| Nonfabric synthetic materials | 0.9 | | 0.011 | |
| Food processing (SIC 20xx) | 1.5 | | 0.008 | |
| Miscellaneous manufacturing (SIC 21,31) | 0.2 | | 0.001 | |
| Agricultural wastes | | 805.1 | | 5.913 |
| Animal wastes (SIC 013x - 014) | 413.4 | | 2.779 | |
| Crop wastes (SIC 011x - 012x) | 340.0 | | 2.720 | |
| Forest and logging residues (SIC 19xx - 39xx) | 51.7 | | 0.414 | |
| Total combustible wastes and fuel value | | 1,135.1 | | 8.526 |

Note - 1 pound = 0.4536 kilograms; 1 Btu = 252 calories.

tion rate for 1971 (ref. 4). This latter figure represents an energy equivalent of about 1.1 billion barrels (175 million cubic meters) of oil per year, or about 70 percent of the oil imported that year (refs. 4,5).

The fuel value associated with the 1970 waste stream depicted in table 1 represents a yearly waste of 8.5 quadrillion Btu's (refs. 2,3). This is about 12 percent of the total energy requirement of the United States, which approximates some 72 quadrillion Btu's/year (refs. 5,7). Not all of this combustible solid waste is readily available for use as a fuel, however. Although urban-generated waste may qualify as a fuel because it is available in rather concentrated form at appropriate locations, other kinds of wastes from processing, manufacturing, or agricultural operations are often generated in widely dispersed areas. One study (ref. 3) found that only about 1.5 to 3.0 percent of the Nation's total energy requirement could be supplied by our solid waste due to its geographical dispersion, assuming only minimal waste transportation could be justified (the former amount if 500-ton/day plants are economically justifiable, the latter amount if 100-ton/day plants are worth installing). The amount of waste transportation costs that can be borne has increased substantially, however, now that energy prices for conventional fuels have more than quadrupled. Consequently, it may now well be that substantially more than 1 to 3 percent of our energy requirement ought to come from discarded waste materials.

Table 2 is intended to put into perspective what 3 percent of the national energy requirement represents. Three percent is about twice what we used in 1968 to light our homes and offices, and about 20 percent more than what we used that year to air condition them (refs. 7,8). Another way of looking at what an "extra" 3 percent in energy (from solid waste) might mean to the country is the following: One study (ref. 9) estimated recently that there would be an energy penalty of about

Table 2. Major end-uses for energy, 1968 data (refs. 7,8)

| Type of use | Percent of total U.S. energy consumption |
|---|---|
| Transportation (fuel; excludes lubes and greases) | 24.9 |
| Space heating (residential, commercial) | 17.9 |
| Process steam[a] (industrial) | 16.7 |
| Direct heat[a] (industrial) | 11.5 |
| Electric drive (industrial) | 7.9 |
| Feedstocks, raw materials (commercial, industrial, transportation) | 5.5 |
| Water heating (residential, commercial) | 4.0 |
| Air conditioning (residential, commercial) | 2.5 |
| Refrigeration (residential, commercial) | 2.2 |
| Lighting (residential, commercial) | 1.5 |
| Cooking (residential, commercial) | 1.3 |
| Electrolytic processes (industrial) | 1.2 |
| Total | 97.1 |

[a] Includes some use for space heating, probably enough to bring total space heating to about 20 percent.

2 percent associated with providing the pollution control measures of complete $SO_2$ and particulate control at stationary sources, secondary level sewage treatment for the whole country, waste heat dissipation with cooling towers at power plants, and appropriate sanitary landfilling of all of our municipal solid waste. Thus, energy recovery from solid waste could more than offset the energy required to operate these four significant pollution control processes.

## MAJOR WASTES-AS-FUEL PROCESSES UNDER LONG-TERM EPA DEVELOPMENT: ENVIRONMENTAL CHARACTERISTICS

EPA has been involved in furthering the development of major waste-as-fuel technologies in response to its legislative mandate to do R&D on methods which dispose of waste materials in an environmentally acceptable manner. Certainly one of the best "disposal" options available (best economically and environmentally) is to treat the waste in such a fashion as to enable the recovery of its energy and material resource values. That is, why should we necessarily face the difficult environmental control problems associated with the "throw-away" options of improper land disposal or air-polluting incineration of high-Btu wastes? Conceptually at least, does it not make more sense rather to recover the energy and economic value of these high-Btu wastes and to effect such recovery in an environmentally acceptable fashion?

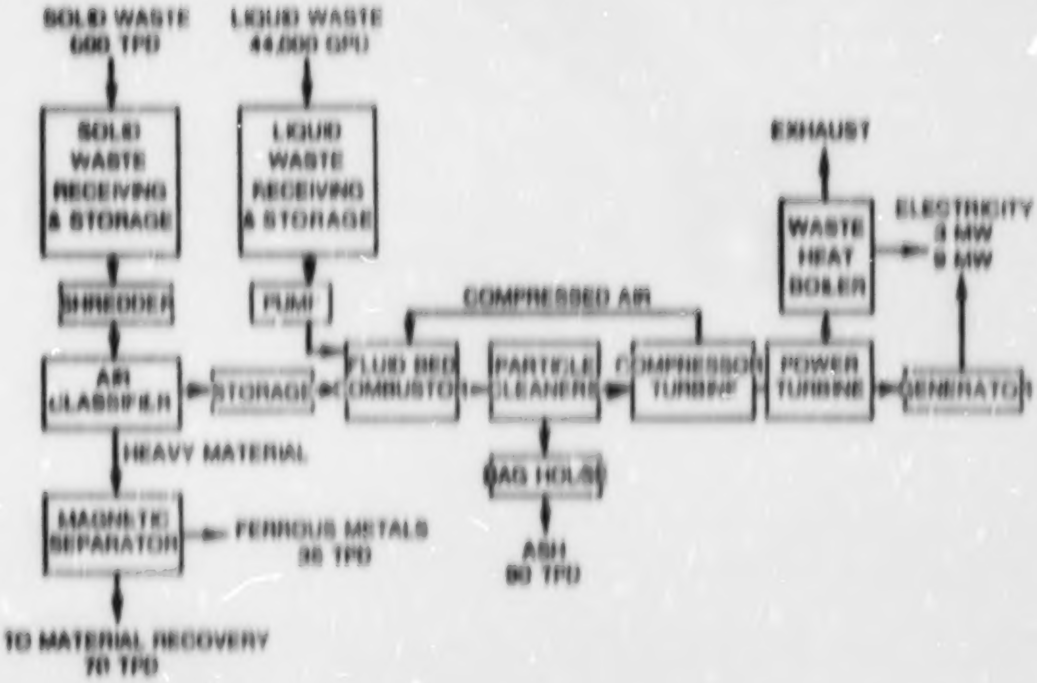
As early as 1967, EPA (actually its DHEW predecessor) began development of several waste-as-fuel processes. Two of the major process options that began to be researched at that time were the CPU-400 System and the Horner and Shifrin Fuel Recovery Process (St. Louis). Table 3 illustrates some of the salient features of these two processes, along with similar data for two other more recently initiated developmental efforts (the Garrett and Monsanto Pyrolysis Processes). Each of these processes will be briefly described—followed by a description of some of the R&D projects begun within the last year in the EPA Wastes-As-Fuel program.

### *The CPU-400 System*

Figure 1 represents a schematic of the CPU-400 Process (refs. 3,10,11). This process uses prepared solid waste to fire a conventional gas turbine for the production of electricity. The solid waste preparation stage is one in which the refuse is shredded, air classified, and placed in a storage vessel prior to use. The combustion system initially consisted of a fluidized bed combustor and three stages of cyclonic inertial separators to remove particulates from the gas prior to its expansion through the turbine. The turbine compressor is used to provide

**Table 3. Some resource recovery processes under development by EPA**

| | EPA's grantee (contractor) | Process | U.S. tons per day (TPD) of solid waste (SW) treated |
|---|---|---|---|
| • | Baltimore, Md.<br>(Monsanto Enviro-Chem) | SW pyrolysis to generate steam & char (LANDGARD) | 1,000 |
| • | San Diego County, Cal.<br>(Garrett Research) | SW pyrolysis to fuel oil and char | 200 |
| • | St. Louis, Mo.<br>(Horner and Shifrin and Union Electric) | SW combustion along with coal at a steam power plant | 300-600 |
| • | (Combustion Power Co., Menlo Park, Cal.) | Direct SW combustion conversion to electricity (CPU-400) | 100 |



SOLID WASTE
600 TPD
LIQUID WASTE
44,000 GPD
SOLID WASTE RECEIVING & STORAGE
LIQUID WASTE RECEIVING & STORAGE
EXHAUST
WASTE HEAT BOILER
ELECTRICITY
3 MW
9 MW
COMPRESSED AIR
SHREDDER
PUMP
AIR CLASSIFIER
STORAGE
FLUID BED COMBUSTOR
PARTICLE CLEANERS
COMPRESSOR TURBINE
POWER TURBINE
GENERATOR
HEAVY MATERIAL
BAG HOUSE
MAGNETIC SEPARATOR
FERROUS METALS
36 TPD
ASH
90 TPD
TO MATERIAL RECOVERY
70 TPD

Figure 1. CPU-400 system.

combustion air, and the whole system operates at about 4 atmospheres pressure. Solid waste is fed into the fluidized bed combustor through two rotary air-lock feeder valves that discharge into a pneumatic transport system.

This solid waste disposal/resource recovery process has been under development through an EPA research contract with Combustion Power Company of Menlo Park, California, since 1967. A 100-ton/day (90,700 kilogram/day) pilot plant employing a 1,000 kW Ruston Hornsby turbine has been developed and is currently undergoing testing. Tests have demonstrated the system's ability to burn solid waste while generating full-power output under complete automatic control. Unfortunately, however, tests have also demonstrated that extensive deposits on the first-stage turbine stators develop after only a few hours of operation. The inertial separators were simply ineffective, permitting too many sticky aluminum and other particles to enter the turbine and result in the deposition problem. The separators were also ineffective from an air pollution control point of view (ref. 12). As can be seen from table 4, which shows the gaseous and particulate emission characteristics of the first configuration of the CPU-400 pilot plant, the particulate loading in the turbine's exhaust reached a high of 1.6 lb/$10^6$ Btu (0.7 grams/$10^6$ joules) (ref. 13). EPA emission requirements for particulates are 0.1 lb/$10^6$ Btu or 0.043 g/$10^6$ J.

To solve the turbine deposition/erosion problem and to develop an effective air pollution control technology for high-temperature/high-pressure applications, a granular filter has been designed and recently installed at the EPA CPU-400 pilot plant. Figure 2 is a sketch of the granular filter design. A continually recirculating, moving bed of $Al_2O_3$ balls having a mean diameter of 0.077 inches (1.96 mm) will remove the particulate from the turbine-bound gas stream. The startup of this filter is scheduled for November 1975.

### *The St. Louis Waste As Supplementary Fuel Process*

A schematic of the Horner and Shifrin Fuel Recovery Process is shown in figure 3 (refs. 9, 10, 11, 14, 15). Municipal solid waste is prepared for firing in a coal-burning utility boiler. The solid waste provides 10 to 20 percent of the fuel requirement and the coal supplies the balance. The solid waste is shredded, and the nonburnables are removed by air classification. The solid waste is then conveyed from a storage bin to a

Table 4. CPU-400 pilot plant emission characteristics[a]

| Flue gas constituent | Exhaust concentration |
|---|---|
| $O_2$ | 15.1% |
| $CO_2$ | 5.2% |
| CO | <30 ppm |
| $CH_x$ | 2 ppm |
| $SO_2$ | <35 ppm |
| $NO_x$ | 100 ppm |
| HCl | 100 ppm |
| Particulate | 1.6 lb/$10^6$ Btu[b] |

[a] During high-pressure, municipal solid waste-burning operation.

[b] Using the ineffective inertial separators, i.e., before installation of the granular filter.

rotary air-lock feeder and then pneumatically injected into the boiler. This system has been under development by Horner and Shifrin and others for the EPA, for the Union Electric Company, and for the City of St. Louis since 1969.

Numerous hours of system testing have been accumulated to date, and the effect of solid waste on slagging, corrosion, precipitator performance, and ash handling requirements have been and are being evaluated. The need for an air classifier was established early when it was discovered that the glass and metals in the feed material were causing serious wear problems in the pneumatic transport system and in the rotary feed valves. Once an air classifier was incorporated into the system, plant performance improved significantly. The technical and economic worth of the process concept has been well established; its overall success has caused a significant increase in plans to utilize this technology across the country.

To define the environmental characteristics of this cofiring (with coal) option, EPA has been sponsoring tests being conducted by the Midwest Research Institute (MRI). Union Electric (UE) has also been carrying out parallel tests of its own. The cofiring of solid waste had

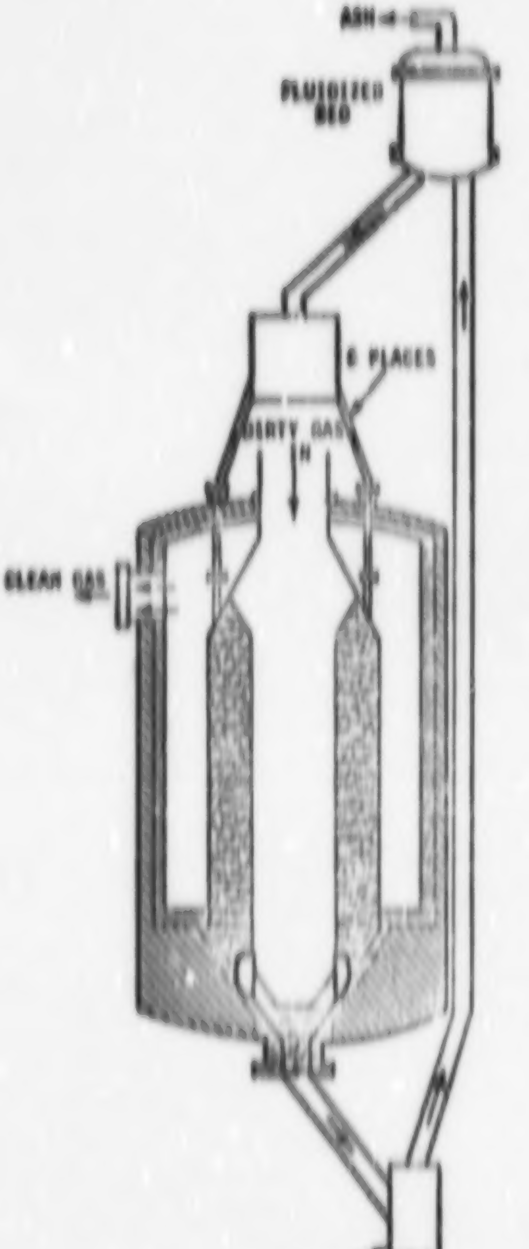


Figure 2. CPU-400 pilot plant granular filter.

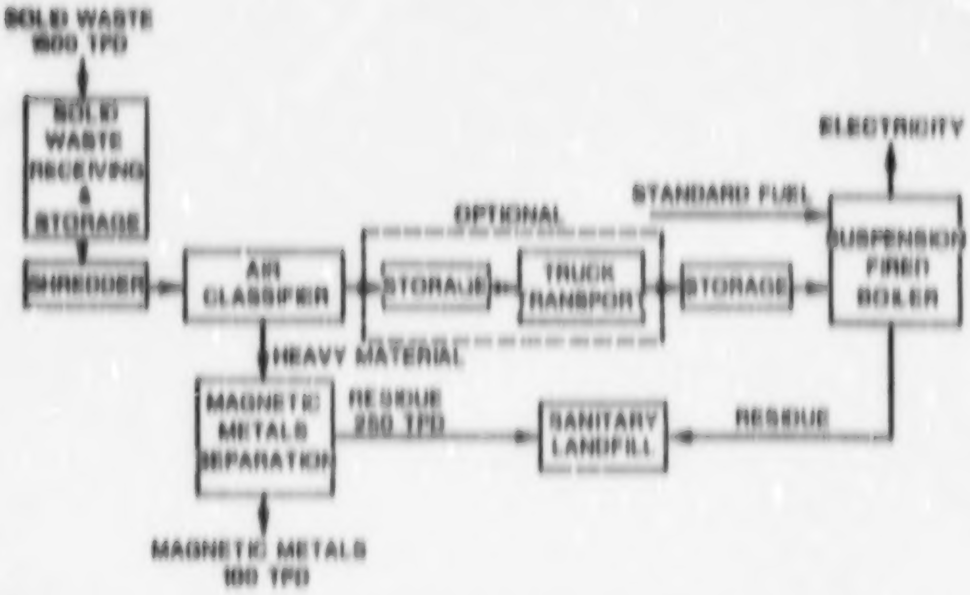


Figure 3. Horner and Shifrin Fuel Recovery Process.

no discernible effect on $SO_2$, $SO_3$, $NO_x$, or $Hg^+$ emissions (refs. 16,17); however, coals with different sulfur contents were used in the coal-only and the coal/solid waste firing operations. Earlier estimates had predicted a 13 percent reduction in $SO_2$ emissions, had solid waste been fired with the same coal to provide 20 percent of the boiler heat input at UE's Meramec station (ref. 15). Emissions of $Cl^-$ increased moderately when solid waste was cofired with the coal (refs. 16,18). The average $Cl^-$ concentration in the stack gas was 17 percent higher when solid waste was cofired. (When coal only was burned, the concentration was 330 ppm.)

Particulate emissions, however, have been considerably more troublesome. Figure 4 presents a comparison of electrostatic precipitator (ESP) efficiencies obtained using the mean values of inlet and outlet grain loadings from the individual UE and EPA/MRI test series run in 1973 (ref. 18). No significant differences in ESP efficiency as a function of fuel mixture were noted in the EPA/MRI tests done at that time. However, efficiencies calculated from the somewhat earlier UE tests did show a marked dependence on fuel mixture—in all UE cases, lower ESP efficiencies resulted from cofiring waste with coal. In tests conducted in May of 1975, EPA/MRI data tended more to corroborate the earlier UE results than the earlier EPA/MRI findings, though the new data points may not be representative (refs. 18,19). To substantiate the worth and validity of these more recent EPA/MRI tests, additional analyses are planned.

Two factors that do influence the collectability of particulate matter in ESP's are known to have some effect during waste cofiring operations. Increased gas flow rates through an ESP and increased particle resistivity tend to reduce ESP efficiency. Gas flow rates are increased when waste is cofired with coal (at a constant power generation rate). Similarly, particle resistivities have been found to be about three times higher during waste cofiring tests than during coal-only tests (refs. 18,19).

*The Garrett Pyrolysis Process*

In late 1972, work began under the joint sponsorship of EPA and San Diego County on the Garrett Pyrolysis Process. Figure 5 is a flow chart of this process (refs. 3,10,11,20). The process employs two stages of shredding, an air classification operation, and a drying operation to produce a minus 14- to 24-mesh fuel for the pyrolysis reactor. The heat required for the pyrolysis is obtained from the combustion of the pyrolysis off gas and a fraction of the char produced. This heat is transferred by means of the heat exchanger. From the pyrolysis unit, the gases are exhausted to a cyclone, which removes the char, and then are scrubbed to remove the product, a highly oxygenated fuel oil, and

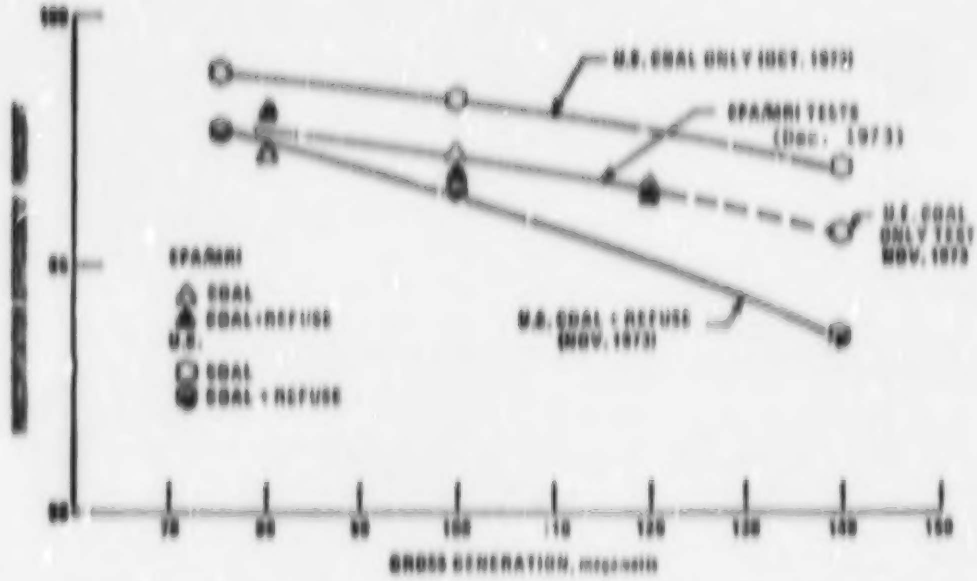


Figure 4. Variation of ESP efficiency with changes in fuel and boiler load.

other solids and liquids. The clean gas has a heating value of approximately 550 Btu's per cubic foot ($4.93 \times 10^6$ cal/m$^3$) and is recycled to the pyrolysis reactor. A 4-ton/day (3,640-kg/day) plant has been tested. A 200-ton/day (182,000-kg/day) plant is currently under construction in San Diego.

The projected environmental characteristics of the San Diego plant include the following: (1) the amount of waste otherwise going to landfill will be reduced by over 75 percent; (2) each ton of waste treated will produce the energy equivalent of 27 gallons of No. 6 fuel oil; (3) when 100 percent pyrolytic oil was burned as a fuel, only 280 ppm of $SO_2$ in the stack gas resulted (though $NO_x$ and HCl emissions may well be higher than when No. 6 fuel oil is burned); and (4) much of the water used (and formed) by the process will be recycled within the process for glass recovery and for char quenching before receiving final treatment (ref. 20).

### *The Monsanto Landgard System*

The Monsanto Landgard Process is shown schematically in figure 5 (refs. 3,10,11,21). It employs a rotary kiln pyrolyzer into which shredded solid waste is fed at one end and air and fuel at the other end. Hot fuel products of combustion contact the solid waste and pyrolysis gases and char are formed. The char and solid waste inerts exit from the kiln at one end into a quench tank while the pyrolysis gas exits from the other end into an afterburner. The gases from the afterburner are used for steam production and then sent through a wet scrubber and exhaust fan. A 50-ton/day (45,500-kg/day) pilot plant has been operated by Monsanto in St. Louis, and a 1,000-ton/day (910,000-kg/day) system (supported partially by an EPA demonstration grant) has recently begun operation in Baltimore.

Groundbreaking ceremonies for the City of Baltimore plant took place in early 1973, and startup commenced in mid-1975. The Baltimore Gas and Electric Company (BG&E) is purchasing the 200,000 lb/hour (91,000 kg/hour) of low-pressure steam produced by the plant (for use in heating and cooling downtown buildings). The projected environmental characteristics of the Baltimore plant include: (1) the savings to BG&E of 15 million gallons of oil per year otherwise needed to generate the steam; (2) the disposal by the city of much of its solid waste at lower particulate emissions than is possible using the city incinerator; and (3) expected $SO_2$ and $NO_x$ emissions of less than 100 and 50 ppm respectively. Groundwater protection may be required to prevent char leachate from entering it, if the char product is not sold/used but disposed of on the land (ref. 21).

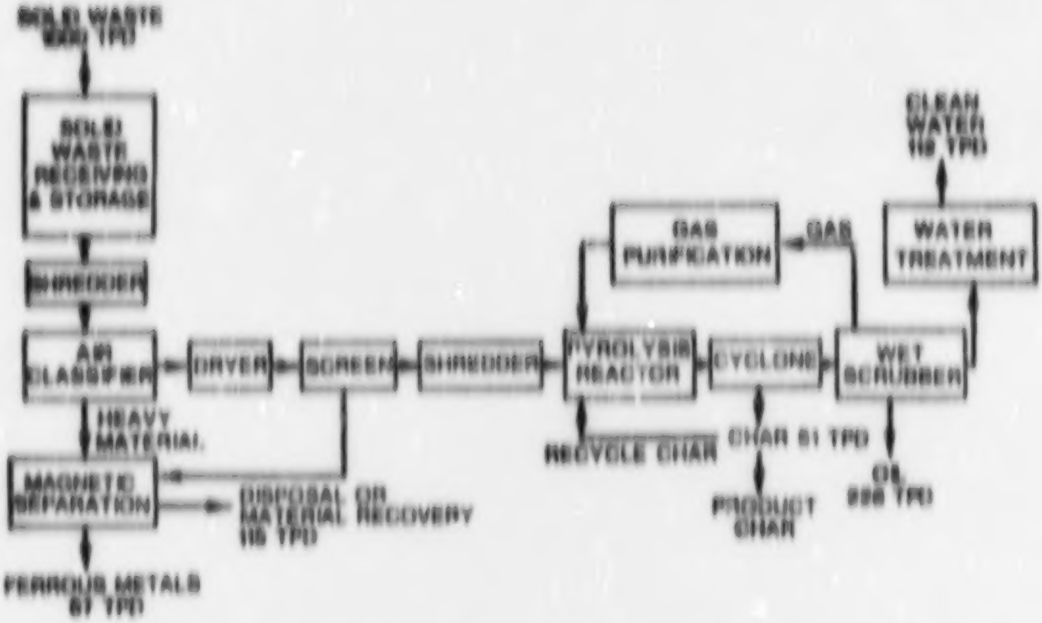

SOLID WASTE
SOLID WASTE RECEIVING & STORAGE
SHREDDER
AIR CLASSIFIER
DRYER
SCREEN
SHREDDER
PYROLYSIS REACTOR
CYCLONE
WET SCRUBBER
GAS PURIFICATION
GAS
WATER TREATMENT
CLEAN WATER
HEAVY MATERIAL
MAGNETIC SEPARATION
DISPOSAL OR MATERIAL RECOVERY
FERROUS METALS
RECYCLE CHAR
CHAR 61 TPD
PRODUCT CHAR
OIL

Figure 5. Garrett Pyrolysis Process.

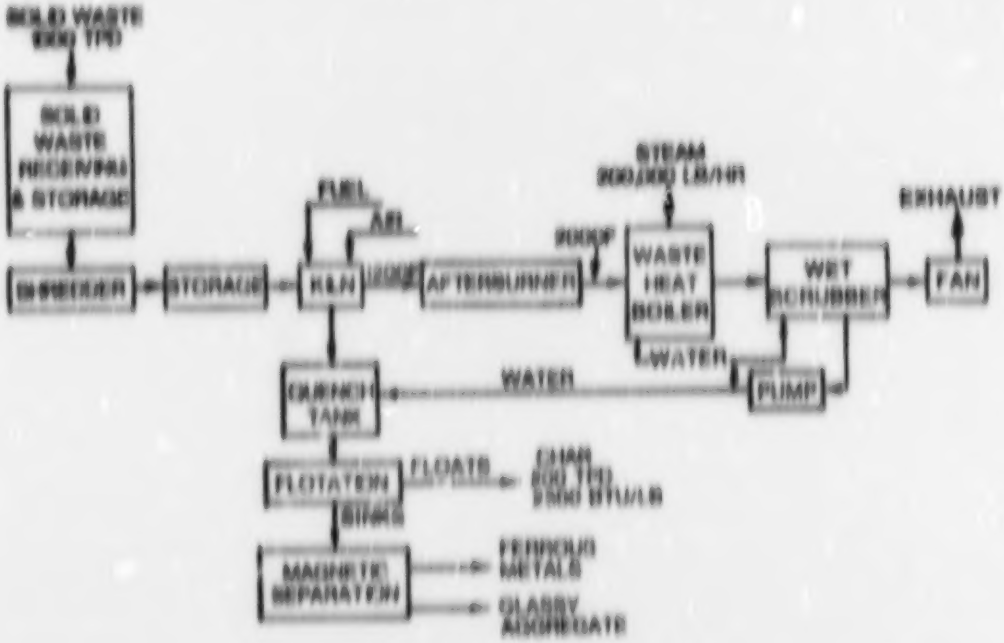

SOLID WASTE
SOLID WASTE RECEIVING & STORAGE
SHREDDER
STORAGE
FUEL
AIR
KILN
AFTERBURNER
STEAM
200,000 LB/HR
WASTE HEAT BOILER
WET SCRUBBER
FAN
EXHAUST
WATER
PUMP
WATER
QUENCH TANK
FLOTATION
FLOATS
CHAR
SINKS
MAGNETIC SEPARATION
FERROUS METALS
GLASSY AGGREGATE

Figure 6. Monsanto Langard System.

## THE CURRENT EPA R&D PROGRAM IN WASTES-AS-FUEL

In addition to the four major processes just described, EPA is actively engaged in furthering the development of, and in environmentally assessing, several other wastes-as-fuel process options. A broad R&D program (a new thrust) in this area has recently been initiated within EPA's Office of Research and Development (ref. 22). This research program will be summarized below with the aim of providing some insight into program rationale.

The current EPA program can be subdivided into four major areas of emphasis. These areas are: (1) Assessment R&D (environmental, technical, economic); (2) Waste Cofiring with Coal, Oil, or Industrial Waste; (3) Waste Cocombustion with Sewage Sludge; and (4) Pyrolysis and Bioconversion Processes.

Table 5 lists those project areas that are illustrative of work ongoing in the first subdivision, Assessment R&D. Work here features environmental, technological, or economic assessments of waste-as-fuel options. Research in "Assessments" includes a study to acquire pollutant characterization data for the competing waste-as-fuel processes as well as to develop environmental assessment criteria and proper sampling/analytical techniques. With these data, R&D will begin on assessing the technology available to control air pollution from these processes and on developing needed control technology. Work is also underway, by the Ralph M. Parsons Company of Los Angeles, on performing a comparative technical and economic evaluation of the developing waste-as-fuel processes. Several waste surveys will be conducted by other organizations in an attempt to better define the energy values of selected waste streams, such as those from industry, from agriculture, and from demolition operations. To spur the coming together of waste producers (e.g., the cities) and waste users (like the power industry), EPA has awarded approximately 10 grants to selected municipalities to allow for appropriate planning of waste-as-fuel utilization or conversion facilities (done under the "Technical Assistance" charter shown on table 5). It is also shown under Assessment R&D on table 5 that work will be done in waste preprocessing. An EPA grant has been awarded to the National Center for Resource Recovery to enable a side-by-side evaluation of existing shredders, air classifiers, etc., to define operating characteristics and efficiency. A state-of-the-art evaluation of other preprocessing techniques for grinding and separating the inorganic and combustible waste fractions will also be performed.

**Table 5. Assessment R&D (environmental, technical, and economic)**

Pollutant characterizations
- Assessment criteria
- Sampling/analytical methodology

Air pollution control technology assessment/development

Process evaluations (parsons)

Waste surveys

Technical assistance (10 cities)

Waste preprocessing
- Side-by-side evaluation (NCRR)
- S-O-T-A evaluation

**Table 6. Waste cofiring with coal, oil, or industrial waste (technical and environmental evaluations)**

With coal

St. Louis/Union Electric

Battelle/City of Columbus

Comparative test burns of cofiring in tangentially-fired versus stoker-fired boilers

Densified waste cofired in an industrial-sized stoker-fired boiler

With oil

Refuse cofiring with oil

With industrial waste

Use of refuse in bagasse boilers: feasibility study (Hawaii)

Table 6 illustrates R&D to be done in the second subdivision of the waste-as-fuel program, in Waste Cofiring with Coal, Oil, or Industrial Waste. Work in this area includes finalization of the work at St. Louis (see "Major Waste-As-Fuel Processes"), which will center on the identification of potentially hazardous emissions associated with waste cofiring with coal. R&D will continue by Battelle at a small Columbus, Ohio, boiler in which varying ratios of coal-to-refuse will be run. Particular emphasis here will be on defining the corrosion rates associated with cofiring. At another site, a comprehensive evaluation will be made of cofiring waste with coal in tangentially fired boilers versus stoker-fired boilers. The evaluation will compare process and environmental characteristics of each option. Yet another coal/waste cofiring option will be tested: that of densifying (e.g., pelletizing) the waste and injecting along with lump coal into an industrial-sized stoker-fired boiler.

Table 6 also lists two other options that will be investigated: (1) the combustible fraction of municipal solid waste will be doubleground and cofired along with fuel oil in existing oil-fired boilers (technical and environmental feasibility will thus be determined); and (2) a feasibility study is underway in Hawaii to determine the value of cofiring solid waste along with bagasse in industrial bagasse boilers.

Table 7 indicates projects recently initiated in the waste-as-fuel area, known as Waste Cocombustion with Sewage Sludge. The first of these projects centers on the utilization of various municipal and industrial wastes (e.g., refuse, tires, wood chips), and/or low-sulfur coal, to combust or incinerate sewage sludge in an existing, full-scale multiple hearth sludge incinerator in St. Paul, Minnesota. The second project shown involves using the CPU-400 pilot plant (see "Major Waste-As-Fuel Processes") to test the process and environmental characteristics associated with cocombusting solid waste and sewage sludge in a high-pressure fluidized bed, the off-gases from which are cleaned upstream of their expansion through a gas turbine for power recovery.

Table 8 lists those R&D projects EPA has underway in the waste-as-fuel areas of Pyrolysis and Bioconversion. The most comprehensive of these is the recently begun research at the Energy Resources Company (ERCO) in Cambridge, Massachusetts. ERCO, with assistance from MIT, will conduct bench and pilot-scale (500-lb/hr or 230-kg/hr) tests on the pyrolytic conversion of mixed waste to fuel. Work at this environmental test facility will feature the pyrolysis of various mixtures of waste (e.g., refuse, industrial wastes, agricultural wastes) at varying residence times (space velocities) and operating temperatures to define what product ratios (of fuel gas to fuel oil to char) are possible and what environmental

Table 7. Waste cocombustion with sewage sludge (technical and environmental evaluations)

St. Paul/Seneca treatment plant sludge incinerator

(Waste supplies the heat to incinerate the sludge in existing multiple-hearth furnace, thereby backing-out conventional fuels that are in short supply and accomplishing the disposal of two wastes instead of one.)

CPU-400: Power recovery while disposing of solid waste and sewage sludge

(Sludge is injected into the four-atmosphere fluid bed along with solid waste, the off-gases from which pass through a granular filter for air pollution control and are then expanded through a gas turbine.)

Table 8. Pyrolysis and bioconversion R&D (technical and environmental evaluations)

Pyrolysis

- Pyrolytic conversion of mixed waste to fuel (ERCO)
- Pyrolytic conversion of solid waste to polymer gasoline (the Navy at China Lake, California)
- Portable pyrolysis of agricultural waste to transportable fuels (Georgia Institute of Technology)

Bioconversion

- Enzymatic hydrolysis of waste cellulose to glucose to an ethyl alcohol fuel (the Army at Natick, Massachusetts) consequences may result. The China Lake Naval Weapons Center is conducting bench-scale research for EPA on upgrading (via polymerization reactions) pyrolytic fuel oil/gas to gasoline. Another R&D effort underway in the waste pyrolysis area is that which is being done at the Georgia Institute of Technology. It centers on the concept of disposing of agricultural wastes by having them processed in a portable van containing a pyrolysis reactor that converts the otherwise wasted material to transportable fuels, such as fuel oil or char. Regarding the last project listed on table 8, the Army's Natick Laboratories are carrying out bench-scale research on converting waste cellulose to an ethyl alcohol fuel by using enzymatic hydrolysis of cellulose to glucose as an intermediate step.

## SUMMARY

The 570 million tons of dry, combustible solid waste discarded each year represent an energy loss of about 12 percent of the total U.S. energy requirement. One-fourth of this amount, or the energy equivalent of about 3 percent, exists in lots large enough to feed energy recovery plants that are sized to handle 100 tons of solid waste per day.

Following a discussion of EPA's legislative mandates in the wastes-as-fuel area of research, four major processes that have been under long-term EPA development were described, as were the environmental characteristics of each. These processes are: the CPU-400 System, the St. Louis Waste-As-Supplementary Fuel Process, the Garrett Pyrolysis Process, and the Monsanto Landgard (Pyrolysis) System.

The current EPA R&D program in wastes-as-fuel was then summarized. Environmental research in this area centers on: (1) Technical, Economic, and Environmental Assessments; (2) Waste Cofiring with Coal, Oil, or Industrial Waste; (3) Waste Cocombustion with Sewage Sludge; and (4) Pyrolysis and Bioconversion Processes.

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# PRELIMINARY ASSESSMENT OF THE ROLE OF ENERGY STORAGE AND IMPLICATED TECHNOLOGIES FOR ENERGY CONSERVATION IN INDUSTRY

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## *Abstract*

*Energy storage is but one possible means for reducing the consumption of fuel and/or electricity within the industrial plant. A twofold approach is underway to identify candidate industries where heat storage can measurably improve energy efficiency and produce a concomitant improvement in operating economics. This paper presents the methodologies selected to identify candidate industries and processes, the nature of available information, and how additional needed data on energy utilization dynamics are being accomplished.*

*Federal Energy Administration and the Energy Research and Development Administration have recognized a needed focus on current energy-related factors describing the industrial sector and programs to explore applicable conservation techniques. In one such program, the role of energy storage, particularly thermal energy, is synthesized into process designs for a first approximation of cost-benefit and energy conservation impacts afforded by inclusion of this function. Examples of near-term planned or feasible energy storage schemes are shown. With some 40 percent of the total energy demand related to industrial requirements including space heat, process and direct heat, and boiler heat for steam, the full spectrum of temperature and energy levels are represented. Matching in-plant available excess or reject energy to other compatible needs separated by a time and/or magnitude function, can represent a real opportunity for an energy storage application. Significant design challenges for accomplishing requisite heat/energy exchange and storage in operational industrial energy systems are recognized and discussed.*

Fifteen years ago a policy decision was made to put a man on the moon by the end of the 1960's, and it was done. During that same decade a second major policy was formulated to deal with our wastes and the resulting degradation of our environment, and it is slowly being done. Most recently we have recognized the abusive practices employed in consuming our once abundant energy resources. We have yet to make significant commitments towards a firm policy to see that this crisis is alleviated. Aggregated forces united in purpose are what make things happen; the moon in 9 years with a work force of 300,000 people; the environment in 7 years with a force of millions; and energy in 17 years with multimillions needed for assured success. A visible target, easily perceived by all involved, is the major impetus in planning conquests and achieving them. The environmental and energy situations are so nonaggregated that a single approach with a manageable supporting force cannot effect a measurable penetration toward achieving the needed objectives. No one approach is going to resolve singly our worsening energy posture. Recognizing this, we can explore one permutation of the energy problem represented by the industrial sector where some 40 percent of our yearly energy supplies are expended.

Energy management is a term that will become a way of life for industry once the several components comprising a corporate energy system are defined and their interactions better understood. As a definition, energy management is a purposeful program of *defining* realistic energy demands, *planning* interactive processes and facilities to achieve highest practicable efficiencies in their operations and therefore the lowest energy consumption profiles consistent with each product's value and market demand, and their *implementation*.

## *Overview of Energy and the Industrial Sector*

Unlike its nearest energy-consuming relative, the electric utility industry has not formulated the sophisticated data and statistical records that are the starting point for effective energy management. While the reasons may be obvious, nevertheless it takes these kinds of record-keeping to objectively formulate conservation potentials and assess their impacts. The author has been engaged in a study aimed at determining applications and developing conceptual designs of thermal energy storage systems responsive to these applications. To this end, a review of industrial energy consumption was conducted with the express goal of citing regions and industry within these regions expected to be hard pressed energy-wise because of energy shortages and/or high costs. A second thrust involved a review of basic process designs within each major industry in a more classic engineering attack on energy inefficiencies. The major constraint in this second effort is the dearth of available data describing the dynamics of process operations. The Federal Energy Administration (FEA) funded several studies to describe energy conditions in major industrial groupings. While each provided insights never amassed previously on the processes and factors involved, none explored *real time* energy, those as impacted by throughput, process design, shift operations, seasonal and day-of-week variability, and the effect of each on energy consumption and efficiency. Within the bounds of this situation, energy storage is one approach of many needed within the industrial energy system to more effectively utilize industry's main ingredient—energy.

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*Energy Sources for Industry*

Project Independence studies have forecast energy demands ($11/bbl oil with conservation) through to 1985 by sector (table 1), and for the industrial sector by fuel/energy source (table 2).

Gradual changes in the source of industrial energy have taken place over the years. Coal use has been steadily declining in recent years due to pollution requirements and the ready availability of natural gas and oil. This trend is projected to reverse due to, among other factors, limited natural gas supply and greatly increased petroleum prices. The historic gradual increase in electrical consumption is projected to accelerate as the United States increases its nuclear generation capability.

A regional split of these fuels for 1971 shows the characteristics of large uses of fuels contiguous to their region (table 3).

As an example, coal is heavily consumed where it is produced, due in part to high transportation costs. Iron and steel, the largest industrial coal consumers, have located at their primary energy source rather than their raw material source. The top four coal-producing census regions are responsible for about 81 percent of U.S. coal production and in turn consume about the same percentage. Similar scenarios exist for natural gas and oil.

Although industrial consumption of electricity represents only 10 percent of industry energy, certain industries consume a considerably higher percentage. Primary aluminum is the most notable example, requiring over half its energy as electricity. This factor, com-

Table 1. Net distrubed energy — quadrillion Btu

| Sector | 1968 | 1970 | 1972 | 1977[a] | 1980[a] | 1985[a] |
|---|---|---|---|---|---|---|
| Residential/commercial | 15.35 | 16.72 | 17.94 | 18.24 | 19.66 | 22.59 |
| Industrial | 21.09 | 22.32 | 22.94 | 24.12 | 25.51 | 27.93 |
| Transportation | 15.54 | 16.69 | 18.07 | 17.71 | 18.16 | 19.13 |
| Total | 52.00 | 55.74 | 58.95 | 60.07 | 63.33 | 69.65 |

[a]Projected.

Table 2. Source of industrial energy — percent

| | 1968 | 1970 | 1972 | 1977[a] | 1980[a] | 1985[a] |
|---|---|---|---|---|---|---|
| Coal | 24.3 | 22.4 | 18.7 | 19.8 | 21.4 | 21.9 |
| Petroleum | 22.9 | 23.0 | 24.9 | 28.5 | 28.8 | 28.8 |
| Natural gas | 44.0 | 45.6 | 46.4 | 39.6 | 37.1 | 35.4 |
| Electricity | [illegible]8 | 9.0 | 10.0 | 12.1 | 12.7 | 13.9 |
| Total | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |

[a]Projected.

Table 3. Regional industrial energy sources — percent

| Census region | Coal | Petroleum | Natural gas | Electricity | |
|---|---|---|---|---|---|
| New England | 1.9 | 58.9 | 17.6 | 21.6 | 100.0 |
| Middle Atlantic | 41.9 | 18.7 | 25.9 | 13.5 | 100.0 |
| East North Central | 41.2 | 8.1 | 38.8 | 11.9 | 100.0 |
| West North Central | 12.8 | 11.0 | 64.5 | 11.8 | 100.0 |
| South Atlantic | 30.1 | 18.1 | 34.8 | 17.0 | 100.0 |
| East South Central | 29.7 | 8.3 | 40.3 | 21.7 | 100.0 |
| West South Central | .4 | 14.7 | 80.3 | 4.6 | 100.0 |
| Mountain | 13.1 | 12.4 | 62.9 | 11.5 | 100.0 |
| Pacific | 4.5 | 16.2 | 59.4 | 19.9 | 100.0 |

bined with a very high energy intensity of about 75 million Btu per ton of product, leads aluminum plants to areas having cheap electric power. Over one half of the industry's electricity is generated by hydroelectric power plants. On a broad basis, an alternate energy concept such as energy storage must be economically (and technically) attractive to enough of the industrial sector to establish a viable market for the device and thereby significantly impact total industrial energy consumption. The changing energy source mix will impose severe economic stresses on all regions with the degree of severity varying in certain regions and energy-consuming sectors. The economic analyses presented here analyzed the input/output inventory of energy by fuel types in each region, reduced to per capita consumption and applied to the demand projections for 1985 (in this case). Shortages/surpluses are allocated according to end-use priority and that growth rates remain even by fuel type. Allocations are made on the basis of percentages of shortages. Resulting demands then are as shown in table 4.

Each consuming sector in each region will have considerably increased expenditures for energy in 1985 from the base year. Using constant dollars to factor out inflationary effects, the expenditure increases can be broken out into three categories:

1. Increases due to increased energy use alone,
2. Increases due to price increase alone,
3. Increases due to energy mix change alone.

This procedure, analogous to variance analysis in accounting, can assist greatly in determining economic stress areas. Item 3 is the prime indicator of stress, since energy shortages and capital expenditures must occur.

Energy price projections become necessary at this point. A matrix of regional and sector prices was derived that was consistent within itself and with the Project Independence projections. These prices and 1971 actual prices were applied to consumption data to yield total industrial energy expenditures (table 5).

Analysis of the 1971 to 1985 expenditure increase yields the following data (table 6).

The Middle and South Atlantic and West North Central regions are the likely stress areas in terms of fuel mix changes. An even more compelling stress is the prospect of energy supply curtailment. The industrial sector will feel the heaviest impact of the gas shortage under present curtailment schedules. The economic effects of curtailments can quickly make economic effects of high energy costs seem insignificant.

There are certain industries in which natural gas is the only fossil fuel that can provide process heat and still maintain product purity. Glass is a prime example, with many northeastern glass producers facing almost certain shutdowns in coming months. Since the regenerative furnace most commonly used in glass manufacture requires about 2 weeks to stabilize in temperature, even a 1- or 2-day fuel curtailment would involve a substantial loss of production.

Oil and coal can use several means of distribution including tank cars, trucks and barges so that "black marketing" and "leakages" buffer absolute controls of

Table 4. Projected 1985 industrial energy source $10^{11}$ Btu

| Region | Consumption | Coal | Oil | Gas | Electricity |
|---|---|---|---|---|---|
| New England | 494 | 12 | 303 | 28 | 152 |
| Middle Atlantic | 3,265 | 1,258 | 1,186 | 289 | 532 |
| East North Central | 6,033 | 3,180 | 1,290 | 773 | 796 |
| West North Central | 1,441 | 175 | 721 | 325 | 220 |
| South Atlantic | 2,774 | 695 | 1,203 | 311 | 565 |
| East South Central | 1,832 | 557 | 37 | 265 | 523 |
| West South Central | 8,324 | 36 | 1,138 | 6,729 | 421 |
| Mountain | 1,268 | 132 | 193 | 801 | 142 |
| Pacific | 2,500 | 76 | 1,457 | 442 | 525 |
| Total | 27,932 | 6,121 | 7,528 | 9,963 | 3,870 |

Table 5. Industrial energy expenditures – millions \$[a]

| | 1971 | 1985 |
|---|---|---|
| New England | \$ 648 | \$ 1,752 |
| Middle Atlantic | 3,344 | 9,102 |
| East North Central | 4,730 | 12,170 |
| West North Central | 956 | 4,544 |
| South Atlantic | 2,086 | 7,182 |
| East South Central | 1,354 | 4,125 |
| West South Central | 2,841 | 13,444 |
| Mountain | 671 | 2,601 |
| Pacific | 1,709 | 5,974 |

[a] Source: 1971, Census of Manufactures; 1985, GE analysis.

Table 6. Expenditure increase — 1971 to 1985

| | Total increased expenditures | Due to volume | Due to price | Due to mix change |
|---|---|---|---|---|
| New England | $ 1,104 | 285 | 825 | -6 |
| Middle Atlantic | 5,758 | 1,077 | 3,663 | 1,018 |
| East North Central | 7,440 | 2,100 | 6,214 | -874 |
| West North Central | 3,588 | 336 | 1,448 | 1,804 |
| South Atlantic | 5,096 | 952 | 3,537 | 607 |
| East South Central | 2,771 | 439 | 2,226 | 106 |
| West South Central | 10,603 | 1,288 | 9,281 | 34 |
| Mountain | 1,929 | 336 | 1,444 | 149 |
| Pacific | 4,265 | 1,024 | 3,330 | -89 |

oil apportionments. Therefore, there is greater flexibility of overcoming oil shortages, though at higher costs, to secure needed supplies, where gas users have little recourse of curtailed supplies.

*Energy Storage*

Functional types of energy storage compatibilities are shown (tables 7 through 11 and figs. 1 through 3). Of these, water and rocks have been most widely used for thermal storage, particularly in the European residential/commercial sector. Energy conservation through off peak electrical usage was successfully implemented in Europe using thermal storage for room heating. Batteries have found use predominantly as backup to primary power in case of outages. Other than for spinning reserve, flywheel technology has not been economical. Technical breakthroughs in materials developments and/or structural design are needed. Each of the other methods requires some complex or erratic interaction with current systems to mature a design approach compatible with in situ installations, codes, and institutional barriers. Nevertheless, as the value of energy commodities continues upward, newer, more challenging concepts will fall into favor for a bona fide benefit, measured as cost or fuel savings. An indication of the approximate availability of various advanced energy storage methods is shown in figure 3.

Selection of a particular form or product of energy storage must consider minimizing conversion steps, as from 20 percent to 50 percent efficiency losses are common for each conversion. Conversely, the stored form must satisfy the system requirements; for example, if a 3-month time lag is required between charge and discharge of a stored energy form, a thermal storage technique would most probably be eliminated in favor of a chemical storage method such as hydrogen or methane. So, there are criteria defined not only by the total energy system but also by user needs. Each application can, and will, have several possible solutions depending on what optimizations are required.

1. *Thermal Storage Technologies and Status.* The current ERDA-sponsored program, being carried out at the GE-Space Division has reviewed the status of thermal storage technologies and devices. A survey of available literature was conducted to compile a listing of devices applicable to thermal energy storage. Table 12 lists the results of this survey and includes results from both private and government-sponsored research projects, as published in the literature.

2. *Chemical Energy Storage* has focused about hydrogen and methane reactive concepts and battery developments. Hydrogen storage forms have been tried as a liquid, compressed gas, and in hydrided metals. Liquid hydrogen at cryogenic temperatures has been handled, stored, and safely transported as part of manned space flight programs among other uses. While several accidents and mishaps have occurred (ref. 2), there is little doubt that industrial capability can be easily adapted to overcome these situations. The nature of $H_2$ storage being cyclical, embrittlement due to stress fatigue needs further R&D.

Table 7. Energy storage methods

| Methods | | Energy density (Btu/ft$^3$) |
|---|---|---|
| Hydroelectric (pumped water @ 100 ft head) | | 14 |
| Steam | 15 PSI @ 212° F | 40 |
| | 130 PSI @ 347° F | 360 |
| | 500 PSI @ 467° F | 1,270 |
| Water | 15 PSI @ 212° F | 9,000 |
| | 130 PSI @ 347° F | 16,000 (see figure 1) |
| | 500 PSI @ 467° F | 21,000 |
| Hydrogen | | |
| • Gas | 15 psi @ 60° F | 280 |
| | 1,000 psi @ 60° F | 18,500 |
| • Liquid | 15 psi @ -425 | 200,000 |
| • Hydride | ($Mg_2Ni$, or FeTi) | 250,000 |
| Ammonia | | 340,000 |
| Methanol | | 430,000 |
| Gasoline | | 830,000 |
| Batteries | | See table 11 |
| Flywheels | | See figure 2 |
| Compressed gas | | |
| Cryogenic magnetic fields | | |
| Sensible heat materials | Low temp. | See table 8 |
| Phase change materials | Low temp. | See table 8 |
| Sensible heat materials | High temp. | See table 9 |
| Phase change materials | High temp. | See table 10 |

Hydrided metals are excellent storage materials in that high energy densities are attainable with the hydrogen in a neutral condition and the reactivity controlled by low temperatures, -80° F to charge and 200° F to discharge an iron-titanium hydride bed. Hydrides for storage have not yet been demonstrated on a large scale, however, a near-term application is entirely feasible technically. Brookhaven National Laboratories have been researching and experimenting with metal hydrides for some years. Iron-titanium alloys, among other alloys, have the potential for forming hydrides. The Brookhaven researchers performed an initial evaluation of three methods of hydrogen storage, as $LH_2$, compressed gas, and in hydride form. The results were based on a large-scale system and showed hydrides, compressed hydrogen, and liquid $H_2$ ranked in that order.

*Methane* is employed in two chemical heat pipe designs, the first uses carbon monoxide, reacting to water in the (Adam-Eve) process, while the second employs carbon dioxide, forming hydrogen and carbon

Table 8. Thermal energy storage materials

| Phase change materials | Melting point, °F | Heat of fusion, Btu/lb | Heat capacity Btu/ft$^3$ [a] |
|---|---|---|---|
| Salt hydrates | | | |
| $K_2HPO_4 \cdot 6H_2O$ | 52-56 | 47 | 4,900 |
| $Ca(NO_3)_2 \cdot 4H_2O$ | 117 | 66 | 7,650 |
| $MgCl_2 \cdot 6H_2O$ | 239 | 71 | 6,940 |
| $Na_2SO_4 \cdot 1/2NH_4Cl \cdot 1/2NaCl \cdot 10H_2O$ | 55 | 78 | 7,200 |
| $Na_2S_2O_3 \cdot 5H_2O$ | 113-120 | 90 | 9,200 |
| $Na_2SO_4 \cdot 10H_2O$ | 90 | 108 | 9,900 |
| Organic waxes | | | |
| C14 paraffin | 35-40 | 71 | 3,420 |
| C16 paraffin | 58-65 | 88 | 4,190 |
| 1-decanol | 40-45 | 85 | 4,590 |
| P116 paraffin | 116 | 90 | 4,380 |

| Sensible heat materials | Specific heat, Btu/lb | Heat capacity, Btu/ft$^3$ [a] |
|---|---|---|
| Water | 1.0 | 1,250 |
| Concrete | 0.21 | 610 |
| Stone | 0.20 | 640 |
| Iron ore | 0.16 | 980 |
| Scrap iron | 0.115 | 1,100 |

[a] Based on 20° F temperature change.

Table 8. Properties of selected "prime" thermal energy storage materials utilizing sensible heat

| Material | Heat Density Btu/ft$^3$ (10$^3$)* HS–2,000°F OT–1,000°F | HS–1,500°F OT–1,000°F | HS–1,000°F OT– 200°F | HS–600°F OT–200°F | Thermal conductivity Btu/hr–ft °F | Containment |
|---|---|---|---|---|---|---|
| MgO | 6.7<br>5.3 | 3.3<br>2.7 | 3.7 | 1.9 | 1–10 | Mild steels |
| CaO | 5.3 | 2.7 | 2.9 | 1.6 | 0.5–3 | Mild steels |
| BeO | 9.5 | 4.2 | 4.7 | 2.5 | 5–30 | Mild steels |
| B | 9.0 | 4.5 | 5.0 | 2.7 | 5–20 | Mild steels |
| $Al_2O_3$ | 7.5 | 3.7 | 4.1 | 2.3 | 1–10 | Mild steels |
| $ZrO_2$ | 12.0 | 6.0 | 6.6 | 3.6 | 1–10 | Mild steels |
| Fe | 9.0 | 4.5 | 5.0 | 2.7 | 40–70 | Mild steels |
| $SiO_2$ | 4.8 | 2.4 | 2.6 | 1.5 | 0.1–1 | Mild steels |
| NaCl | 6.8 | 3.4 | 3.7 | 2.0 | 1–10 | Mild steels |
| $Fe_3C$ | 9.2 | 4.6 | 5.0 | 2.8 | 1–10 | Mild steels |
| LiF | | 4.7 | 6.4 | 2.4 | 0.1–10 | 300 series SS |
| 73NaF/27MgF$_2$ | | 5.4 | 8.6 | 3.3 | 0.5–3 | 300 series SS |
| 67LiF/33MgF$_2$ | | | 8.7 | 3.3 | 0.5–3 | 300 series SS |
| $Sb_2O_3$ | | | 20.0 | 9.0 | 0.5–3 | Mild steels |
| $Sb_2O_3$ | | | | 6.9 | 0.5–3 | Mild steels |
| LiOH | | | | 3.3 | 0.5–3 | 300 series SS |
| $Mg(NO_3)_2 \cdot 6H_2O$ | | | | 2.0 | 0.5–3 | Mild steels |
| Glycerol | | | | 1.6 | 0.1–1 | Mild steels |

*HS – Heat source temperature; OT – Operating temperature.

The values for the heat source (HS) and operating temperatures (OT) were arbitrarily chosen to reflect present day needs. Any other values of (HS) and (OT) will have little or no influence on materials selection.

## Table 10. Properties of selected "prime" thermal energy storage materials utilizing the latent heats

| Operating Temperature Range, °F | Material | Heat* Storage Temp., °F | (1) ΔHf BTU/lb | (2) ΔHs BTU/lb | (3) ΔHv BTU/lb | Heat** Density BTU/ft³ (x 10⁻⁴) | Thermal Conductivity BTU/hr-ft-°F | Containment |
|---|---|---|---|---|---|---|---|---|
| | Si | [illegible] | [illegible] | | | [illegible] | [illegible] | |
| | B | [illegible] | [illegible] | | | [illegible] | [illegible] | |
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| [illegible] | $H_2O$ | [illegible] | | | [illegible] | [illegible] | [illegible] | Mild Steels |
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| | $H_2O$ | [illegible] | [illegible] | | | [illegible] | [illegible] | Mild Steels |

*Based on melting point, sublimation point or boiling point.

**A material's heat density is based on its latent heat multiplied by its mass density.

(1) Latent Heat of Fusion.

(2) Latent Heat of Sublimation.

(3) Latent Heat of Vaporization.

Blanks in the last two columns of Table 10 indicate no data is available.

Table 11. Review of current battery technologies[1]

| System | Performance Wh/lb | Performance W/lb | Cycle life | Projected cost | Problems |
|---|---|---|---|---|---|
| Lead-acid | 10 | 20-30 | 1,500 | $ 80/kWh | |
| Nickel-iron | 25 | 60 | ? | $100/kWh | Gassing, maintenance efficiency |
| Nickel-zinc | 30 | 150 | 200-400 | Same as Lead-acid? | Life |

Metal - gas battery performance

| System | Performance Wh/lb | Performance W/lb | Problems |
|---|---|---|---|
| Iron-air | 40-50 | 10-20 | Cathode corrosion, life |
| Zinc-air | 40-50 | 10-20 | Life, cost |
| Nickel-hydrogen | 30-40 | ? | Volume, life |
| Zinc-oxygen | 50-60 | 10-30 | Life, cost |
| Cadmium-oxygen | 30-40 | ? | Life, cost |
| Zinc-chloride | 50-75 | 40-60 | Life |

Alkali metal - high-temperature battery performance

| System | Performance Wh/lb | Performance W/lb | Cycle life | Problems |
|---|---|---|---|---|
| Sodium-sulfur (beta alumina) | 80-100 | 80-100 | 200-2000 | Life, costs |
| Sodium-sulfur (glass) | 80-100 | 80-400 | 100+ | Life, materials stability |
| Lithium-sulfur | 100 | >100 | 2000 | Materials corrosion, costs |
| Lithium chlorine | 60 | >>100 | 100 | Life |

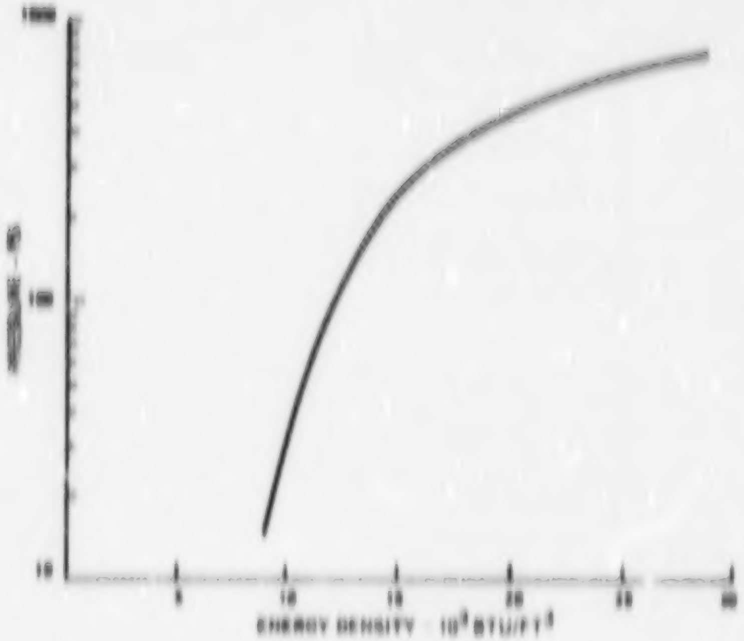

Figure 1. Energy density of water vs. pressures.

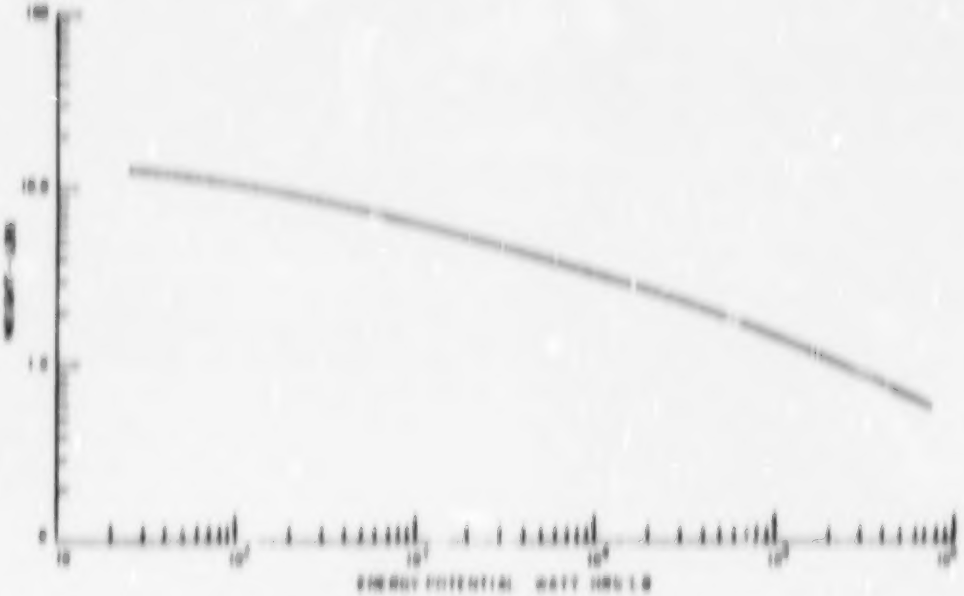

Figure 2. Flywheel energy capacity.

|  | PRESENT (1976) | 1985 | 2000 |
|---|---|---|---|
| PUMPED HYDRO | → |  |  |
| COMPRESSED AIR OR STEAM | → |  |  |
| SENSIBLE HEAT STORAGE ($H_2O$, OIL ROCKS) | → |  |  |
| LEAD ACID BATTERIES | → |  |  |
| ADVANCED BATTERIES |  | → |  |
| LATENT HEAT STORAGE |  | → |  |
| FLYWHEELS |  | → |  |
| HYDROGEN |  | → |  |
| CHEMICAL STORAGE |  |  | → |
| SUPERCONDUCTING MAGNETIC STORAGE |  |  | → |

Figure 3. Availability of energy storage.

monoxide (GE HyCO). This latter concept, being explored by ERDA and the author's company follows the reaction:

$$CH_4 + CO_2 \overset{\text{HEAT}}{\rightleftarrows} 2H_2 + 2CO$$

with the spontaneous absorption of a large endothermic level of reaction across a heat exchanger at 700° to 1,000° C.

The system is a closed-loop scheme, allowing the endothermic reaction to occur near/at the heat source and the exothermic reaction at the end use point via a catalytic reactor. Gases used are easily handled by current hardware. A schematic of this system is shown (fig. 4).

***Batteries*** represent the only perfected method available for bulk electric storage. They have been deployed in many fixed and mobile applications. Their major limitations are weight, capacity, and life. Their very nature of operation requires that modularity (multiplicity) be a design parameter for any specific application, i.e., number of plates, electrolyte quantity/cell, number of cells, etc. Table 17 reviewed current battery technology and future potential battery materials configurations with commensurate estimates of performance and cost projections. It is generally believed by developers of advanced electrochemical (battery) systems that a decade will be needed to prove the stated potentials of the leading near-term concepts, thus limiting electrical storage capability to present lead-acid based hardware.

3. *Mechanical Storage—Flywheels and Compressed Air.* Mechanical energy storage includes pumped-hydro, steam, flywheels, and compressed air. Pumped-hydro systems have been developed for both underground and conventional uses. Siting considerations preclude practical application in an industrial setting for any one industry.

***Flywheels*** have the innate ability to provide mechanical and electrical energy. Using appropriate linkages, differentials, rotation, or oscillatory (piston) power can be derived. By inclusion of coils and inductive pickoffs, a.c. or d.c. voltage can be generated. Small flywheels have been placed in cars, small buses, and commuter trains, indicating the power and portability intrinsic to flywheel usages. Flywheels have been used for emergency power backup, aircraft carrier catapults, and to store wind power-generator output (in the U.S.S.R.). Basic limitations facing use of the hardware are related to materials and structural design. Most known flywheels

Table 12. Thermal energy storage devices

| [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
|---|---|---|---|---|---|---|
| [illegible] | L | [illegible] | [illegible] | — | [illegible] | A |
| [illegible] | L | [illegible] | [illegible] | — | [illegible] | A |
| [illegible] | L | [illegible] | [illegible] | — | [illegible] | A |
| [illegible] | L | [illegible] | [illegible] | [illegible] | [illegible] | A |
| [illegible] | L | [illegible] | [illegible] | [illegible] | [illegible] | B |
| [illegible] | L | [illegible] | [illegible] | — | [illegible] | C |
| [illegible] | S | [illegible] | [illegible] | [illegible] | [illegible] | D |

Table 12. Thermal energy storage devices (cont.)

| Device | Class (Letter Sec.) | Principle of Operation | Application | Economic Considerations | Material Components | Reference |
|---|---|---|---|---|---|---|
| Therm-Bank® "CAN" Thermostore | L | [illegible] | [illegible] | [illegible] | [illegible] | E |
| TES Regenerator | L | [illegible] | [illegible] | — | [illegible] | F |
| Imbedded Refrigerant Module | L | [illegible] | [illegible] | [illegible] | [illegible] | G |
| Steam Accu-mulator | L | Stores heat in the form of steam for off-peak use | [illegible] | [illegible] | Standard pressure vessels | H |
| Rock or Gravel Bin | S | [illegible] | [illegible] | [illegible] | [illegible] | I |
| Shell and Tube TES | L | [illegible] | [illegible] | — | [illegible] | J |
| Heat Storage Heat Exchanger | L | [illegible] | [illegible] | — | [illegible] | K |

## Table 12. Thermal energy storage devices (con.)

### NOTES FOR TABLE 12

A. Smithsonian Science Information Exchange, Inc., Research Information Package 1631 Energy Storage, April 1975.

B. G. G. Libowitz, *Metal Hydrides for Thermal Energy Storage*, Allied Chemical Corp., Morristown, N.J., Paper #749035 presented at IECEC Conference, August 1974.

C. R. Richter, *Solar Collector for Thermal Power System*, Volume III, Xerox Corporation/Electro-Optical Systems.

D. A. F. Clark, J. A. Day, W. C. Dickinson, L. F. Wouters, *The Shallow Solar Pond Energy Conversion System: An Analysis of a Conceptual 10-MWe Plant*, Lawrence Livermore Laboratory, January 25, 1974.

E. *Design, Construction, and Testing of a Pilot Model Heat Storage Unit Based on the Heat-of-Fusion System*, Final Report, Comstock and Wescott, Inc., July 1963.

F. *Solar Heating and Cooling of Buildings, Phase 0, Feasibility and Planning Study Volume*, Final Report, General Electric Company, Document No. 74SD4219, May 1974.

G. H. Yeh, *Conservation and Better Utilization of Electrical Power by Means of Thermal Energy Storage and Solar Heating*, Phase III Report, University of Pennsylvania, March 1973.

H. *Solar Thermal Electric Power Systems, System Studies and Economic Evaluations*, Final Report Volume 2, Colorado State University and Westinghouse Electric Corp., November 1974.

I. *Conservation and Better Utilization of Fuel*, University of Pennsylvania.

J. M. Altman, *Conservation and Better Utilization of Electric Power by Means of Thermal Energy Storage and Solar Heating*, University of Pennsylvania, October 1, 1971.

K. U.S. Patent 3,452,720, "Heat Storage Heat Exchanger," W. T. Lawrence, to Hooker Chemical Corp., Niagara Falls, N.Y., July 1, 1969.

are of steel construction, yielding relatively poor energy storage/pound of material (fig. 7). Although there have been significant improvements in steel flywheel energy density capacity and efficiency, the hazard problem is serious enough to result in derating to a fraction of their theoretical maximum performance (usually 50 to 60 percent derated). The next generation of hardware will utilize new structural design techniques and aerospace-developed material composites. With tensile strengths of 300,000 psi and a low weight/mass ratio, the safety aspects are radically improved. Among candidate materials are Kevlar, fiberglass, bulk glass, wood, and carbon products. Rotational speeds, to produce ~30 wh/lb are below 3,600 RPM, well within bearing, lubrication, and seal state of the art.

The flywheel has a unique characteristic in that its power density can be tailored to rotational speed and/or demand levels and duration. The flywheel is an ideal absorber of off-peak power where in an in-plant generation installation, thermal needs can exceed electrical load demands. Electrical generation can be continued to produce the needed heat, with the excess power fed into the flywheel reserves for later use in any power profile. A typical system configuration utilizing flywheel kinetic storage is shown (fig. 8).

*Compressed air storage* for power is commonly envisioned for power tools, pneumatic lifts, and for engine starting. Man-made gas storage vessels (as opposed to caverns or abandoned mines) are less demanding of siting restrictions relative to environmental impact; however, they do require substantial volumes (hence above-ground appurtenances). The primary use for this storage scheme would be for augmenting peak power periods of say 3 hours with a recharge rate of about 8 hours. The tradeoff here involves sizing of compressor flow to recharge, stored pressure, tank size and, of course, peak demands. A schematic of a compressed air storage system is shown (fig. 9).

In essence, all mechanical storage schemes are best suited to offsetting peak-load periods of relatively short duration (~4 hours). The main advantage is, being able to use off-peak power hence lowest cost power. Massive use of this concept allows upwards of 60 percent reductions in power generation equipment design and commensurate savings in transmission and distribution networks.

### *Applicable Data of Industrial Energy Usages*

The energy data base for each major using sector is nowhere more nonaggregated and/or nonstandardized than for industrial consumption. Residential/Commercial energy usage is largely monitored as a byproduct of utility loads tracking for purposes of anticipating load

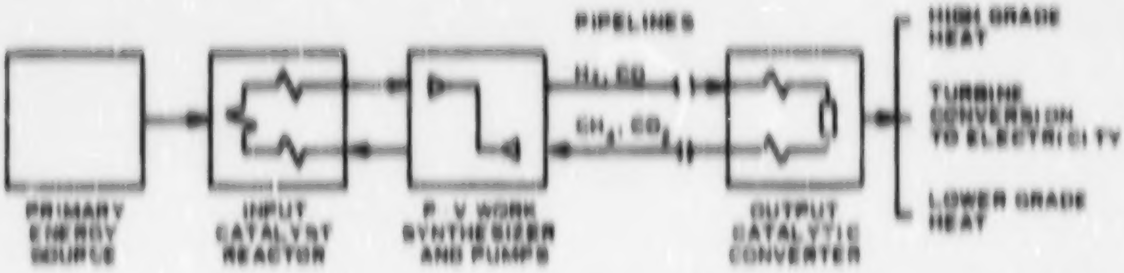
PIPELINES
$H_2$, CO
$CH_4$, $CO_2$
PRIMARY ENERGY SOURCE
INPUT CATALYST REACTOR
P. V WORK SYNTHESIZER AND PUMPS
OUTPUT CATALYTIC CONVERTER
HIGH GRADE HEAT
TURBINE CONVERSION TO ELECTRICITY
LOWER GRADE HEAT

Figure 4. Schematic of a closed-loop system.

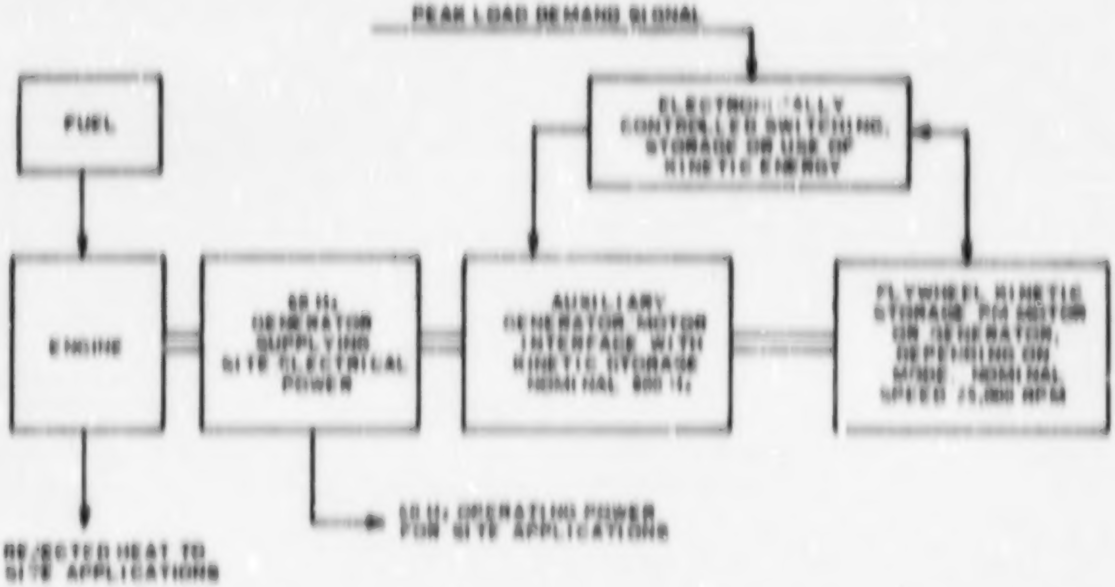
PEAK LOAD DEMAND SIGNAL
FUEL
ELECTRONICALLY CONTROLLED SWITCHING, STORAGE OR USE OF KINETIC ENERGY
ENGINE
60 Hz GENERATOR SUPPLYING SITE ELECTRICAL POWER
AUXILIARY GENERATOR/MOTOR INTERFACE WITH KINETIC STORAGE NOMINAL 800 Hz
FLYWHEEL KINETIC STORAGE ON MOTOR OR GENERATOR, DEPENDING ON MODE. NOMINAL SPEED 15,000 RPM
60 Hz OPERATING POWER FOR SITE APPLICATIONS
REJECTED HEAT TO SITE APPLICATIONS

Figure 5. Onsite power generation with kinetic storage for handling peak loads (typical basic configurations).

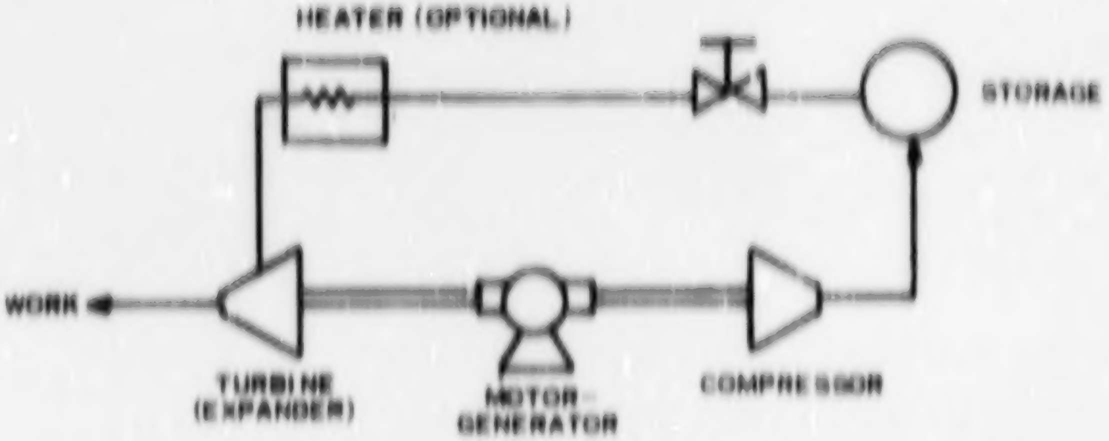

Figure 6. Compressed air storage-based energy systems.

patterns and peaking trends on their systems. As primary residential and commercial energy use is tied to space heating and hot water functions (about 75 percent), climate and season play a major role in regional consumption. The industrial plant uses only about 5 percent of its energy demand for these functions (for employee support). Production functions utilize the overwhelming amounts of energy. These effects are easily seen in a graph of energy consumption of each sector (fig. 7). Conspicuous for the residential and commercial sectors are the winter and summer peaks (heat and cooling) essentially absent from the industrial plot. With utilities providing most of the energy used in the residential and commercial sectors there are sufficient (though imprecise) methods to derive energy use patterns. Industry purchases large amounts of coal, gas, oil, and electricity and internally apportions their uses to the unique features comprising their individual process energy systems design. These uses and their resulting energy demands are shrouded in secrecy to protect competitive positions or proprietary processes.

Rough estimates have been made of energy use in certain industries. Percentages for each general form are shown (table 13). This provides only a surface view of industrial requirements. More data are clearly necessary to identify potential energy conservation candidates. A major reason for the lack of in-depth data is that, until relatively recently, energy use was not the political and technical stewpot that marks current concerns, hence accountability was haphazard or nonexistent because energy sources were reasonably cheap, inexhaustible, and readily available. For these reasons, no major statistical records were kept in a form allowing system analysis. Known data sources for industrial energy are tabulated (table 14).

While not purposely attempting to project an overly pessimistic picture, a data base, even if available, would catalog processes and energy flow patterns numbering in the thousands. Details of how each energy source is used and its conversions, such as from oil to steam to electricity, condensing and flash evaporation functions, further camouflage and defy uniform approaches to developing industrywide, summary statistics useful to research and engineering firms for synthesizing energy storage system applications. Thus, the current roster of government-sponsored energy conservation studies includes tasks covering surveys, questionnaire mailings, interviews, and the like to overcome the dearth of information and acquire needed data for R&D priority setting efforts. In many of the interviews conducted thus far in the ERDA-sponsored thermal energy storage feasibility study now underway, many respondents indicate that (1) the data are not available, (2) no program exists to decipher their plants energy uses, or (3) no dedicated energy analysis personnel are employed and that the job is relegated to a catch-all individual, i.e., industrial or plant engineer. Unfortunately, until a centralized data-reporting system is designed and formulated to protect proprietary information and/or production strategies linkable to energy use patterns, analyzing energy uses dynamics by other than company personnel is at best an intelligent guess and not likely to result in new equip-

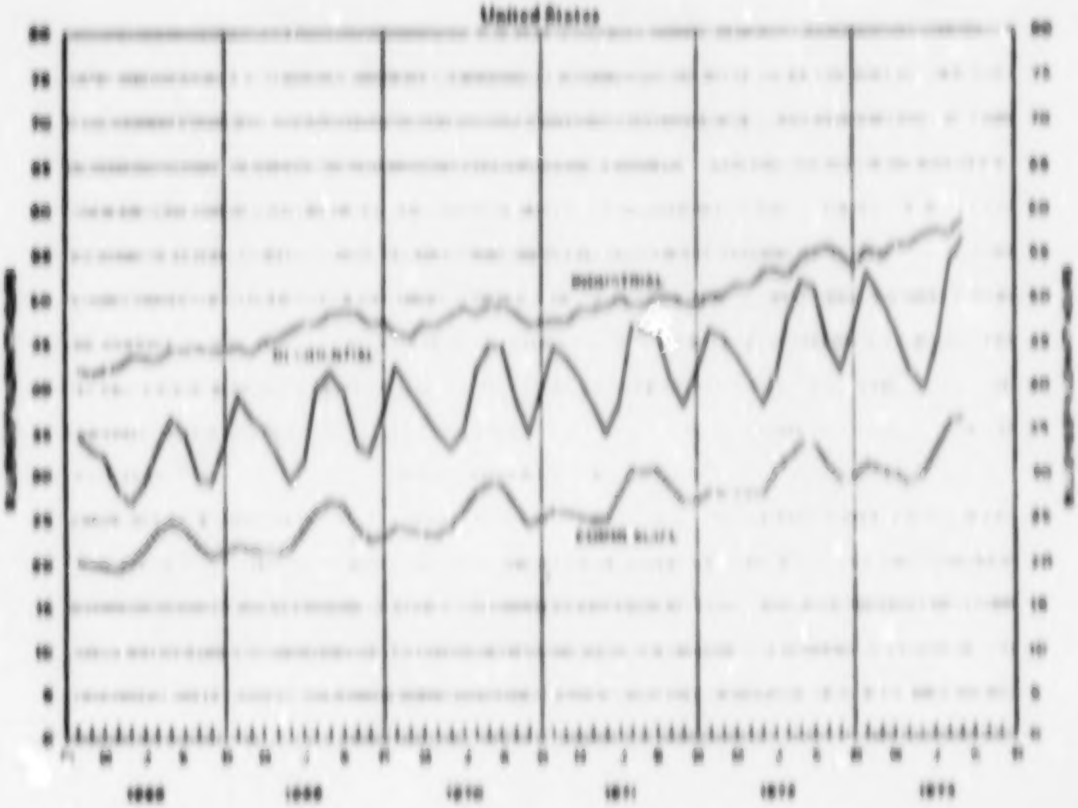

Figure 7. Industrial, commercial, and residential demand–historical.

ment designs due to uncertainties of performance requirements.

*Industry Thermal Demands and TES*

Several TES applications have been identified in the ongoing ERDA-GE TES study. These applications are independent of feasibility studies of technology requirements. A review of industrial processes is performed to develop TES potential not to judge the risks, investments, or energy/cost factors. The volatile nature of energy flow precludes ruling on the ultimate merits of these and other applications yet to be conceived. The final recommendations will, however, rank TES applications in a relative matrix of priorities considering economics, energy impact, and state-of-the-art aspects of each scenario.

Energy demand patterns (hour-by-hour load profiles) are a critical determinant of the feasibility and desirability of thermal energy storage systems. Load profiles are required both to size thermal energy systems and to quantify operating cost savings associated with the resulting load curve. One of the biggest obstacles to a systematic identification of the potential for increased use of thermal storage systems is the lack of organized data. There is no lack of raw data; rolls of strip charts and file cabinets filled with circular charts are not in a form directly useable for systems studies. To develop "typical" daily profiles for different time periods (monthly, seasonal, etc.) and regions of the United States, it is necessary to analyze the raw data, filter out the special cases, and identify typical energy demand patterns. Probably because load profile information is of little use in industry except for in-plant generation studies and troubleshooting exercises, very little has been done in the way of data analysis and categorization. By way of examples, several industrial settings are presented below considering steam demands. Steam production consumes some 30 percent of industrial

Table 13. Industrial energy use by function percent distribution of industrial energy

| Industry | Process steam | Direct process | Space heat | Purchased electricity | In-plant generation | Mechanical drive |
|---|---|---|---|---|---|---|
| Paper and allied products (SIC 26) | 76-80 | 6-9 | 6 | 5-6 | 6 | 1-2 |
| Chemicals and allied products (SIC 28) | 36-46 | 45-50 | 5 | 6 | 4 | 4 |
| Chlorine/caustic | 53 | ◦ |  | 31 | 16 | - |
| Petrochemical | 29 | 61 |  | 5 | 5 |  |
| Petroleum and coal products | 35 | 60-90 |  | 3 | 1 | 1 |
| (SIC 29) Reentry | 28 | 66 |  | 2 | 4 | - |
| Primary metal | ◦ | 87-96 | ◦ | 8 | 2 | 3 |
| (SIC-33) Steel mill | 18 | 61 |  | 20 | 1 | - |
| Food and kindred products (SIC-20) | 40-60 | 0-6 | 12 | 12 | 1 | 35-45 |
| Stone, clay, and glass (SIC 32) | 1 | 86-93 | 0-5 | 7 | 1 | 7 |

Sources: 1. General Electric Engineering Consultanting Services - C.M. Young; space heating was not separately accounted for. 2. General Electric Industrial Sales Division. As indicated in reference 3, specific plant types were considered. The energy use levels reflect the operation of new plants being evaluated and installed for operation in the late 1970's and mid-1980's. Space heating was not separately accounted for. 3. Westinghouse Corporation. As indicated in reference 4, a detailed study of all industries was performed. Direct process heat includes mechanical drive and all energy uses above 400° F.

## Table 14. Industrial process energy bibliography

1. [illegible]

2. [illegible]

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4. [illegible]

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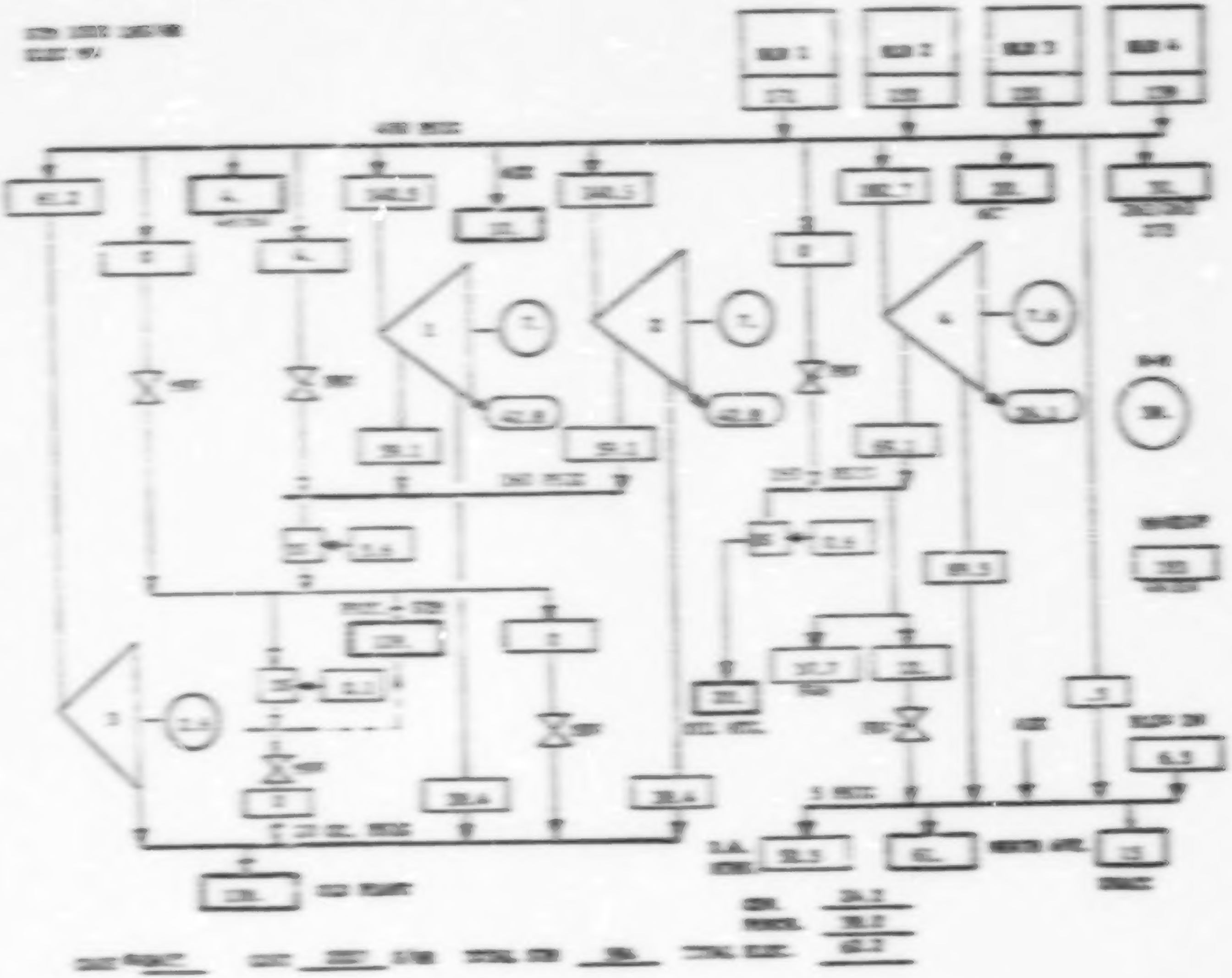


BLR 1
BLR 2
BLR 3
BLR 4

Figure 8. Typical winter steam and electric loads—GE Schenectady plants.

energy demand and represents a major component of process energy impact where thermal storage can be effective.

*Steam Demand Patterns at the General Electric Schenectady Plant*

General Electric's Schenectady plant is a large industrial site where several company divisions are located. The work force consists of a mix of manufacturing, engineering, product development, research and development, etc. Principal products include gas turbines, steam turbine-generators, electric motors, and other electrical equipment.

Although the GE Schenectady plant is probably not a typical industrial facility, an energy use data-gathering effort was undertaken. One of the reasons was to establish problems encountered in collecting and analyzing raw data while another was to test the hypothesis that most industrial loads are flat. The Schenectady plant is a three-shift operation 7 days a week.

The GE Schenectady plant is actually an example of in-plant generation where about two-thirds of the electrical energy is purchased from Niagara Mohawk and one-third is generated on site. The peak electrical demand at the plant is about 80 MW. All of the plant's process heat and space-heating requirements are met with onsite boilers. A simplified diagram showing thermal loads and flows is shown (fig. 8). As illustrated, the thermal energy source is actually four oil-fired boilers, two rated at 300,000 lb/hr and two at 200,000 lb/hr. As indicated, there are four primary steam lines, 400 psig, 150 psig, 5 psig, and 1.25 psig. Although some of the 400 psig steam is used for process heat, most of it is used for power generation. Intermediate-pressure steam for process and low-pressure steam for space heating are made available by using automatic extraction turbines. Although it would have been desirable to determine process-heating loads at the various pressure levels, the required data-processing effort made this impractical. Because of the number of meters at various end use points, calculation of total loads means aggregation of many hourly demands from raw circular chart data. Not all of the raw data are stored at one central source.

Total hourly steam demands (400 psig) for the Schenectady plant were calculated by adding the outputs of the four oil-fired boilers. Hourly steam demands for a summer day, winter day, and spring day are shown (fig. 9). It is important to recognize that these demand profiles are not necessarily typical profiles, since no sampling and data analyses were performed. One of the problems is the fact that total demand information is not readily available; this was developed by summing steam output levels for each boiler. The demand profiles are interesting in that they show significant hour-by-hour and seasonal variations.

It is difficult to explain the specific load variations. Again a significant data analysis effort, correlating steam charts to power charts, is necessary to establish some of the cause-effect relationships.

*Energy Demand Patterns for a Film Manufacturing Plant*

Typical daily profiles of process steam and kilowatt loads for a large photographic film manufacturing plant were tabulated. Steam demands for typical factory days and for weekend days for each of the four seasons are plotted (fig. 10). This particular manufacturing operation has reduced second and third shifts and weekend production.

As indicated (fig. 9), the hourly load variations are in the 17 to 30 percent range. The variation of loads with season is relatively small. As previously indicated, a review of the literature demonstrated that hour-by-hour industrial process heat demand information has not been widely documented. The most complete source of industrial information happens to be a book on the subject of steam storage published in German in 1933 and revised in 1970 (ref. 3). The subject matter of the book deals exclusively with the design and operation of industrial heat accumulators which like district heat are rather common in Europe but seldom found in the United States. Goldstern presents rather detailed discussions of steam storage installations in several industries. Much of the steam demand profile information is reproduced (figs. 11 through 15).

Goldstern indicates that historically the interest in steam accumulators focused on large accumulators, especially in the electric utility industry. As steam pressures increased, however, the application of accumulators became more and more difficult, and they became regarded as obsolescent. The recent fuel shortage has given a new impetus to steam storage. Today, however, the question is "How small can the accumulator be, and at what minimum pressure can it still perform its function?"

Thermal Energy Storage has also been examined for possible applicability in industries and functions other than solely for steam uses. A review of these industries or functions follows.

*In-plant Generation.* Industry will be turning to methods of providing its own electricity with increasing fervor with the continued increase in fuel and electricity costs. Applicability for inplant generation (IPG) is predicated on an industry having significant heat requirements to capitalize on the recoverable heat rejected by a power to bine-generator. The obvious advantage is that

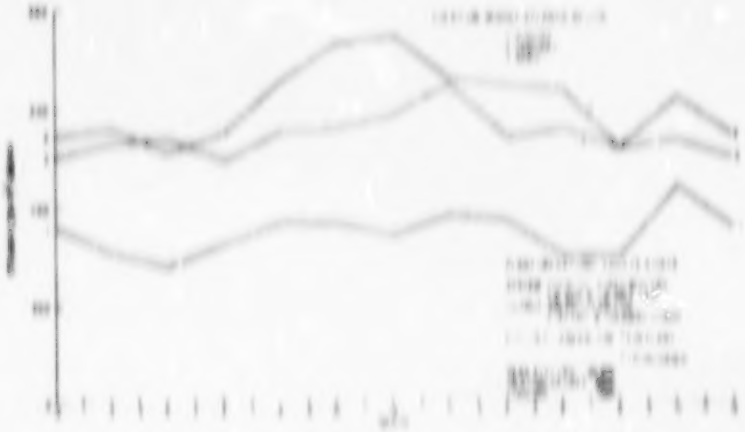


Figure 9. Total steam demand: GE Schenectady plant, location: Middle Atlantic region.

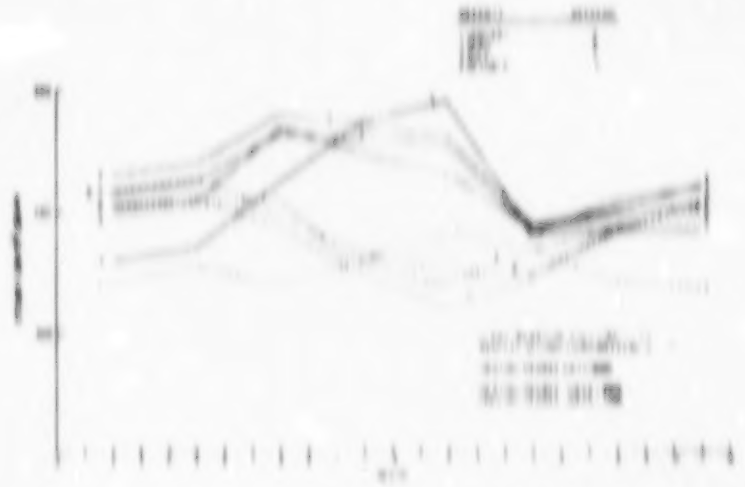


Figure 10. Film manufacture – SIC 3861, location: Mountain region.

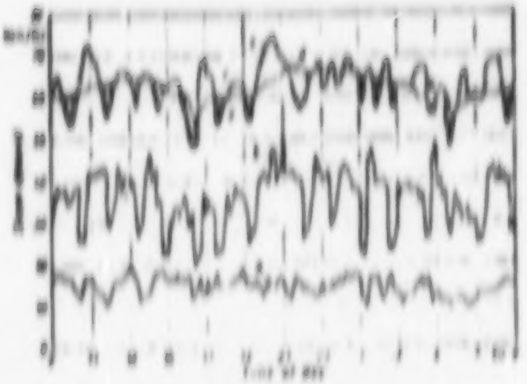


Figure 11. Steam consumption of a sugar factory.

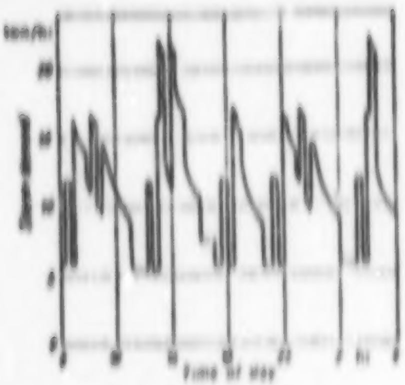


Figure 13. Steam consumption of a paper pulp factory.

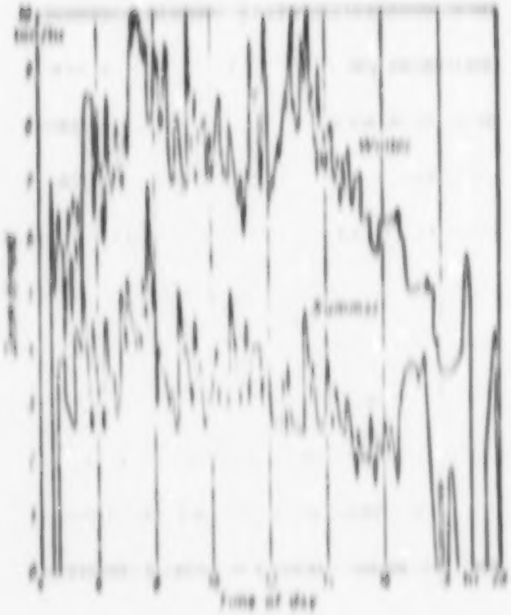


Figure 12. Steam consumption of a textile works in winter and summer.

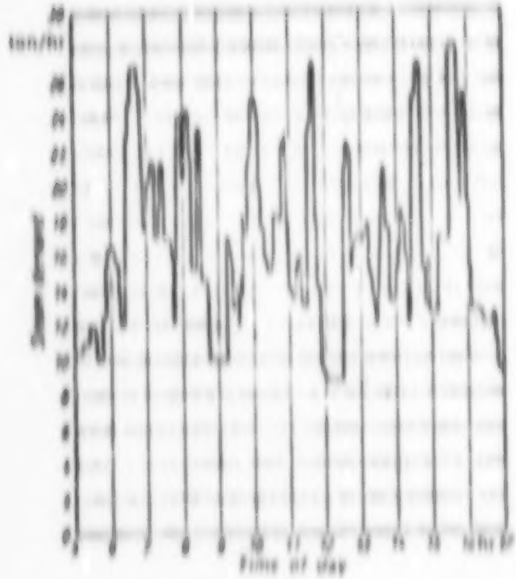


Figure 14. Steam consumption of a carpet factory with laundry.

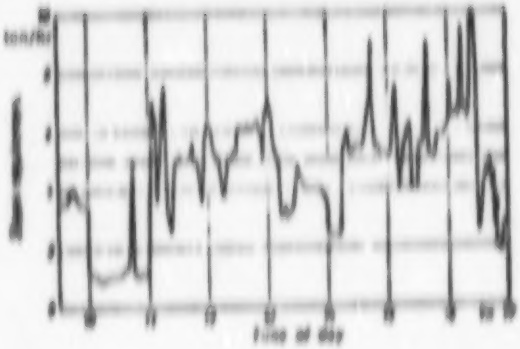


Figure 15. Steam consumption of a carpet factory.

with IPG, a plant can offset its purchased electrical power and recover the exhaust heat for steam or other heat processes previously supplied by a boiler steam system, still requires fuel with an added energy use. Major constraints to IPG uses are the independently varying electrical and/or heat loads causing mismatches in availability. Utilizing heat storage as part of a solar thermal system, heat load following is possible and boiler fuel consumption is offset by the waste energy when available or augmented by a solar thermal system (Fig. 16).

Thermal storage for IPG can be applied at either of two points in an advanced system. Turbine exhausts, usually designed for process steam use, are fed to the TES at temperatures of up to say 500° to 600° when plant steam demands are down. For a system using a solar thermal energy system, or where an alternate waste heat source exists, these heats can be stored and used to supplement boiler power to the turbine if high temperature recovery is planned, or as a feedwater preheater. One such system is now under investigation by GE and a major oil company. A hot oil (~500° to 600° F) is the heat store used to preheat a staged extraction turbine, recovering exhaust heats to maintain oil temperatures. For IPG, thermal storage provides load following or matching where sudden heat demands exceed IPG nominal heat output limits.

*Bricks and ceramics*—Bricks are relatively simple byproducts to manufacture; however, large amounts of heat over the range of from 100° to 1,800° F are required. There are two types of processes, both following

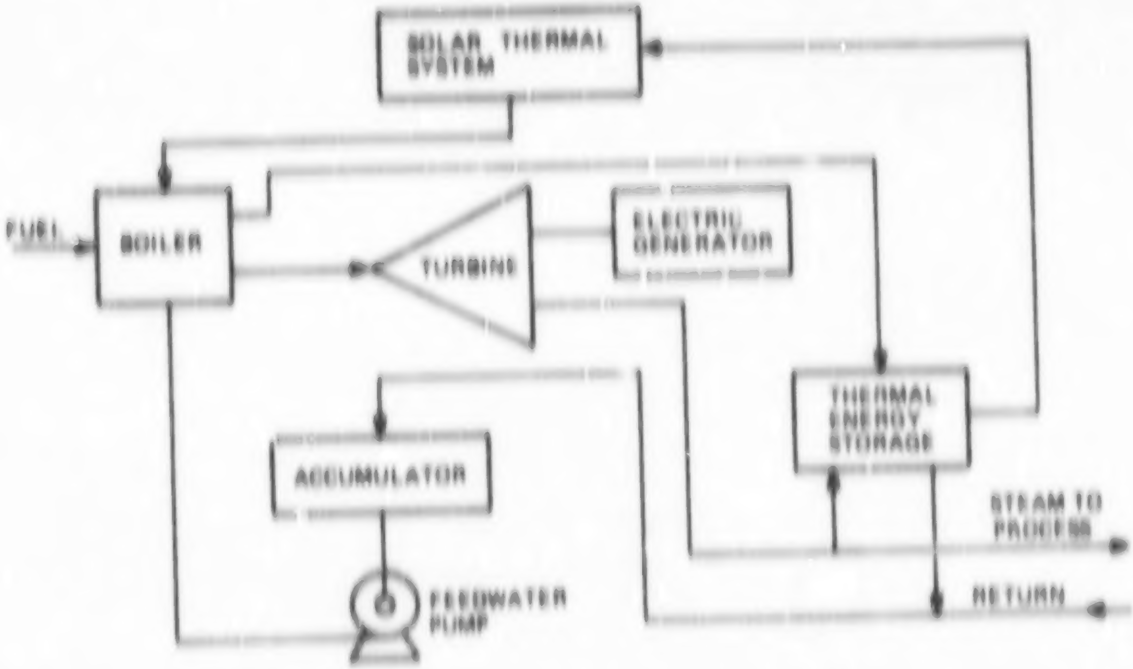


Figure 16. Input generation with solar thermal system.

similar functions but with different operating schemes. The modern continuous (or tunnel) kiln is automated to dry, fire, and then cool the bricks in a present schedule (timing cycle). The bricks enter the kiln (fig. 17) and undergo high air flows and slowly increasing heat (100° to 400° F) to drive off the moisture contained. The timing is extended to allow the entrained water to evaporate slowly, so as not to form steam within the brick, hence forming voids, which weaken the structural strength required. This takes several hours, after which the heat rate is increased at lower air flows to 1,800° F, and bricks are "soaked" until the desired hardness is achieved. Cooldown proceeds more quickly than the heating portion until the shipment exits the kiln. Clean heat must be used during the heating cycle to prevent impurities from penetrating the soft bricks and causing adverse chemical reactions leading to cracking and imperfections of the final product.

The second method uses a periodic kiln (fig. 18). Temperatures are as described for the continuous kiln; however, the time cycle is significantly longer due to the types of bricks produced with this method. As the figure indicates, a 65- to 80-hour heatup period is required. A specific temperature rise-time relationship is followed until the 1,800° F level is reached. A 4-hour "soak" insures that all bricks are uniformly heated before cooling is initiated.

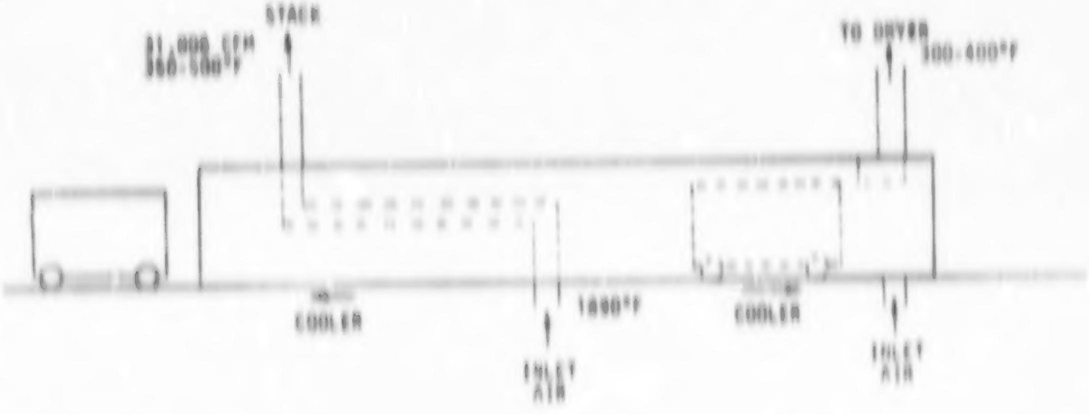
Stored heat may be applicable for the controlled heating phase required to dry the bricks prior to kiln firing up to the cure temperatures. High gas flow rates (18,000-31,000 CFM) are initially applied to carry the high weight of removed moisture from the bricks, stacked in roughly 6-ft × 6-ft × 6-ft cubes on dollies.

TES potentials abound in brickworks plants, particularly where periodic kilns are used. As shown (fig. 19), kilns operate over a wide temperature range and have equally wide heat flow requirements. Brick and ceramic drying and cure (firing) cycles are time-temperature critical to dry residual moisture before using the product. Recovery of convective and conductive heat losses by a TES can supplement dryer heat cycles and "bias" the rigid heat profile, in lieu of excess air controls, an energy-wasting method of thermal control. One such scheme is diagrammed (fig. 20).

*Iron and Steel*

The several stages of ironmaking and steelmaking have differing process heat requirements. In addition, there are several batch type operations identified.

*Coke Processing.* This is a batch process where coke ovens operate in ~20-minute cycles until a supply of coke is processed for the day's steel foundry operations. The American coke ovens quench the baked coke and



- COMBUSTION GASES USED TO PREHEAT INCOMING LOAD
- REMAINDER OF HEAT CONTENT OF COMBUSTION GASES TO STACK (CANNOT BE USED IN DRYER BECAUSE OF IMPURITIES)
- COOLING AIR IS USED FOR DRYING PROCESS

Figure 17. Continuous kiln.

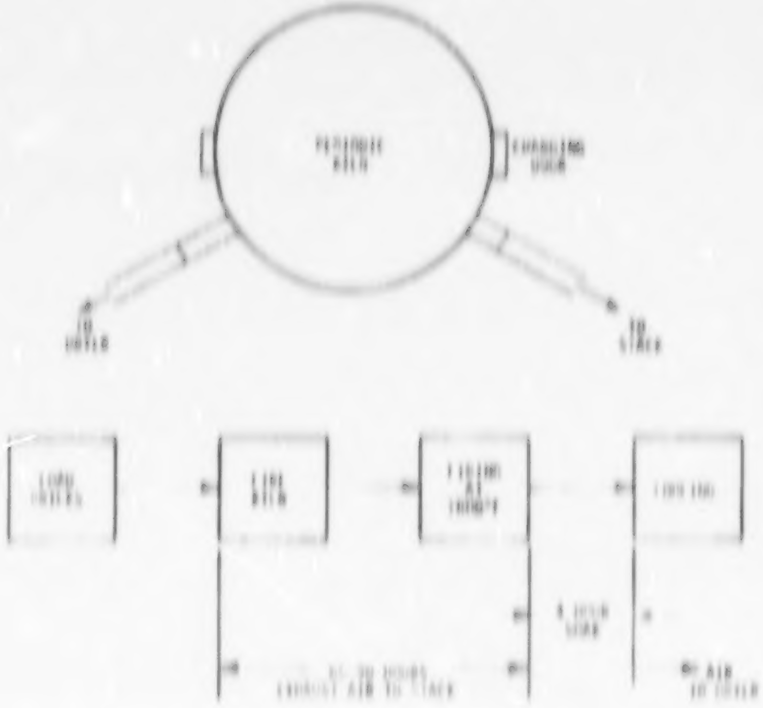


Figure 18. Periodic kiln.

terminate burning. The Russian process (fig. 21) uses the hot coke to create steam for plant use, thereby recovering the sensible heat. A further refinement would be to place the hot coke into a sealed receiver, where through oxygen starvation the combustion reaction will terminate, and, being situated on a TES (fig. 22), the heat is recovered for preheating the next coke oven charge.

*Blast Furnace.* In blast furnace operations, several potentials for heat recovery exist for a TES. In one phase, the slag is periodically removed from the continuously fed furnace. The slag heat content can be stored for use to preheat the scrap charge, annealing ovens, maintain BOF temperatures between charges, or preheat coke before entering the coke ovens. The second use considers the effects of injecting oxygen (~ 5 percent) into the blast furnace to increase temperatures to 3,000° F. Frequently, the furnace temperature overruns and is controlled by excess air. A TES can act as a thermal capacitor absorbing the energy in excess of 3,000° F with a latent heat material reactive at this level as a working fluid (fig. 23).

*Basic Oxygen Furnace (BOF).* This equipment is charged with molten metal and scrap. Heat is raised to 3,000° F using oxygen. Waste gases are exhausted. Between charges, furnace heat levels are maintained through an auxiliary combustion heating system (fig. 24). A TES in conjunction with recovery of the wasted exhaust (3,000° F) can store the recovered heat and be recycled to maintain BOF temperatures between charges or to preheat the scrap, thereby lowering the oxygen needed per charge.

*Electric Furnace.* In addition to the blast and basic oxygen furnaces, the electric furnace is used for periodic high-quality steel. A batch function, these devices accept scrap and other steel charge. Preheating this scrap or steel charge to 800° F has been estimated to reduce energy use 10 percent, electrode wear 24 percent, and increase throughput about 20 percent. If a preheat of 1,800° F is affected, overall energy saved approaches 40 percent. A TES concept for this operation is shown (fig. 25).

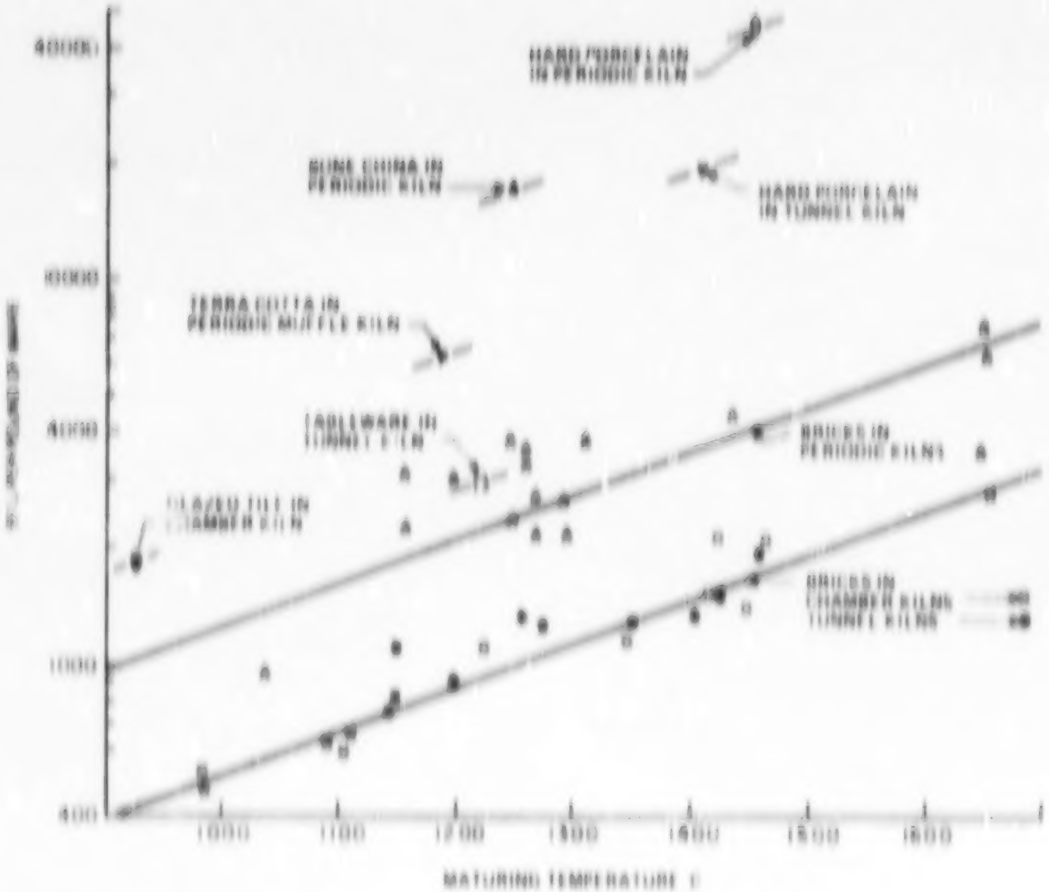


Figure 19. Heat units required for firing in the ceramic industry.

There are many potential applications for heat within a steel foundry. There are also vast amounts of heat wasted in the included processes because of the heretofore lagging energy economy. With increased fuel/energy costs, heat recovery and storage in this industry must be explored in depth. New technology to deal with the high process heats will need to be developed for heat recovery, exchange, and storage. Some additional TES applications, not spelled out above include preheating ladles and ladle lining prior to each pour. Ladle lining preheat is in the range of 300° to 400° F, while ladles require ~1,800° F. Period of heat application can vary from 3 days for linings to 2 hours for preheating ladles.

*Portland cement*

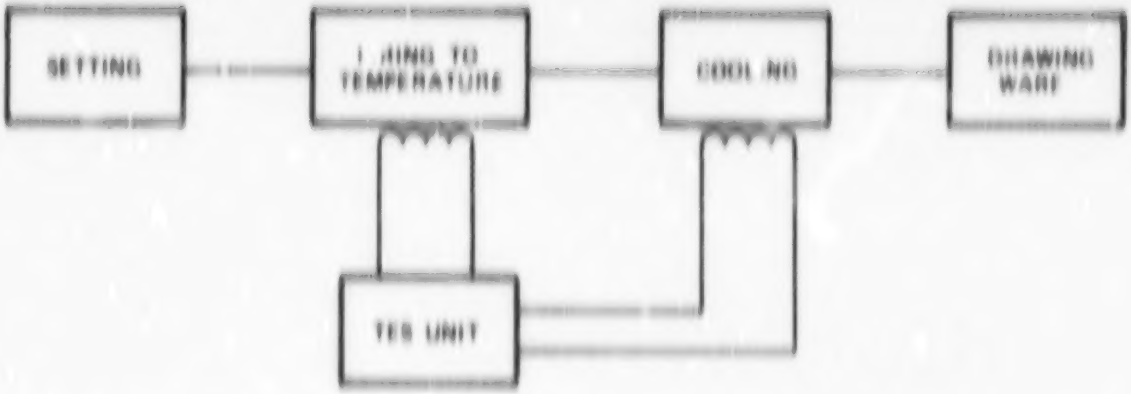
Production may be divided into 4 steps:

1. Raw materials acquisition,
2. Raw material preparation,
3. Clinker production,
4. Grinding and mixing of cement.

Two processes are used in production of cement—wet and dry, with the wet process being the most common in the United States (60 percent). However, the wet process uses 30 percent more energy than the dry process.

Clinker production is the key process in cement production and is the prime area using thermal energy. Raw materials are "burned" in a rotary kiln to form clinkers. The kiln is a long cylindrical, brick lined furnace, which rotates slowly on its axis and is mounted at a slight incline to the horizontal. Raw materials travel through the kiln in about 4 hours and are ultimately heated to about 2,500°-2,800° F at the lower end of the kiln.

The outgoing clinker is cooled, with the heat normally being used to preheat combustion air for the kiln. The wet and dry process is shown (fig. 20).


SETTING
FIRING TO TEMPERATURE
COOLING
DRAWING WARE
TES UNIT

- PERIODIC KILN ≈ 20% EFFICIENCY
- RECOVERY TO TES FROM KILN AND FLUE GASES
- TES ABSORBS ENERGY DURING KILN COOLING
- TES PREHEATS KILN AFTER SETTING

Figure 20. TES periodic kiln concept.

Figure 21. Russian dry cooling.

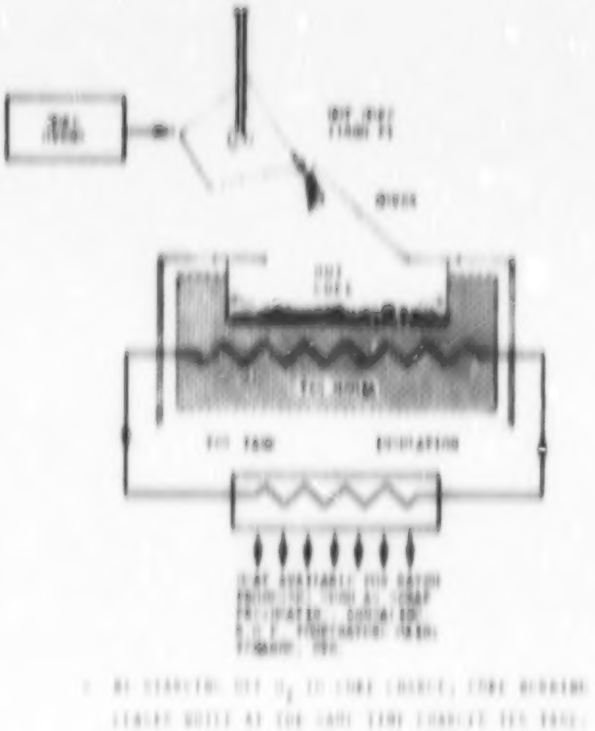

EVAPORATOR

Figure 22. Variation of Russian dry cooling method.

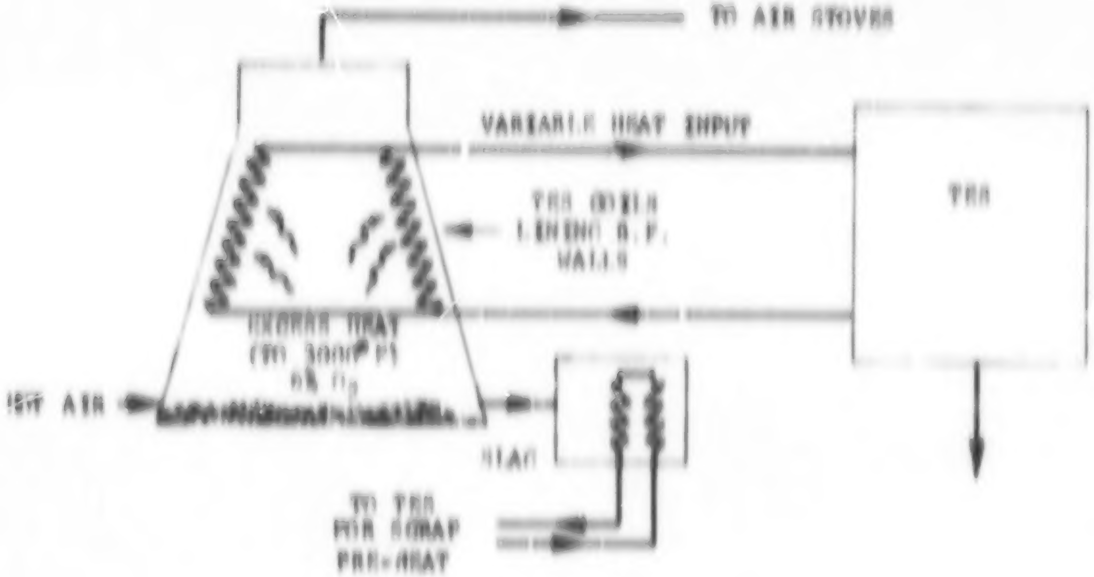

TO AIR STOVES
VARIABLE HEAT INPUT
TES
TES TILES LINING B.F. WALLS
EXCESS HEAT (@ 3000°F)
6% O2
HOT AIR
SLAG
TO TES FOR SCRAP PRE-HEAT

Figure 23. Blast furnace with $O_2$ injection.

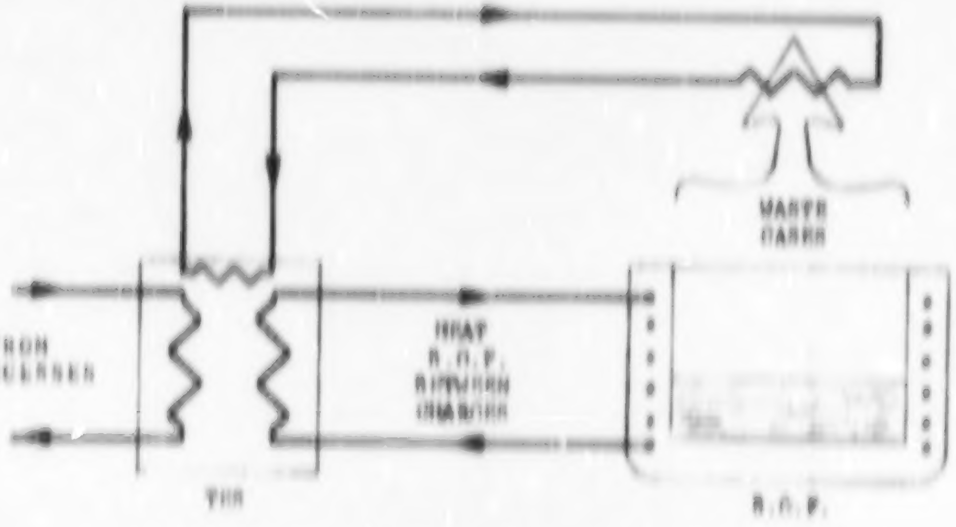

WASTE
GASES
HEAT FROM
OTHER PROCESSES
HEAT
B.O.F.
TES
B.O.F.

Figure 24. Basic oxygen furnace/TES application.

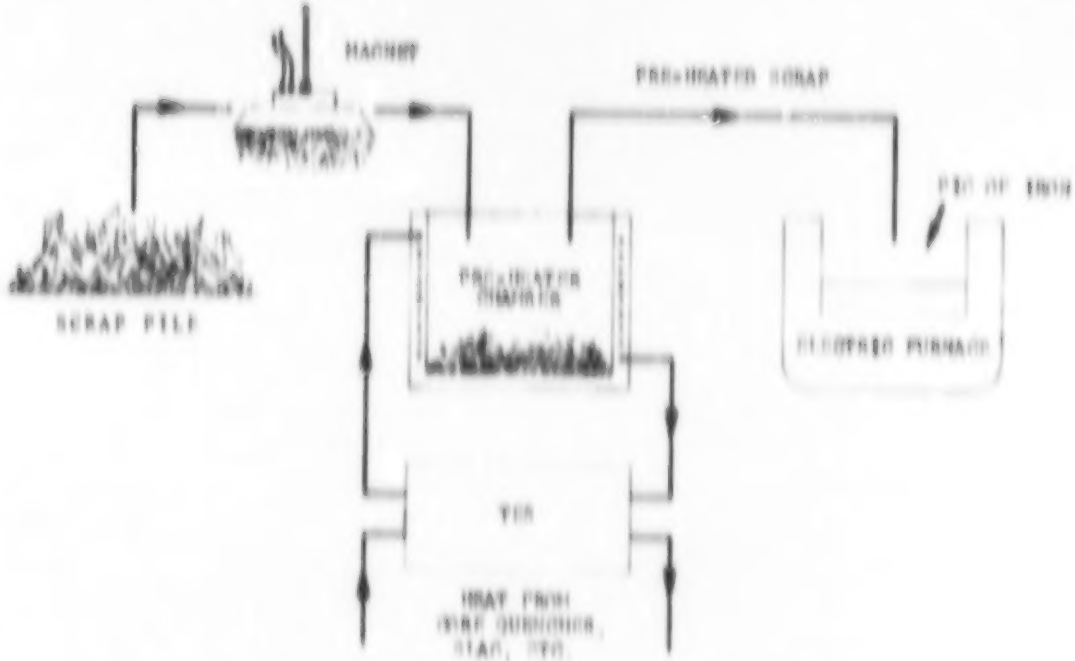

MAGNET
PRE-HEATED SCRAP
SCRAP PILE
TES
ELECTRIC FURNACE
HEAT FROM
OTHER SOURCES,
SLAG, ETC.

Figure 25. Electric furnace/TES application.

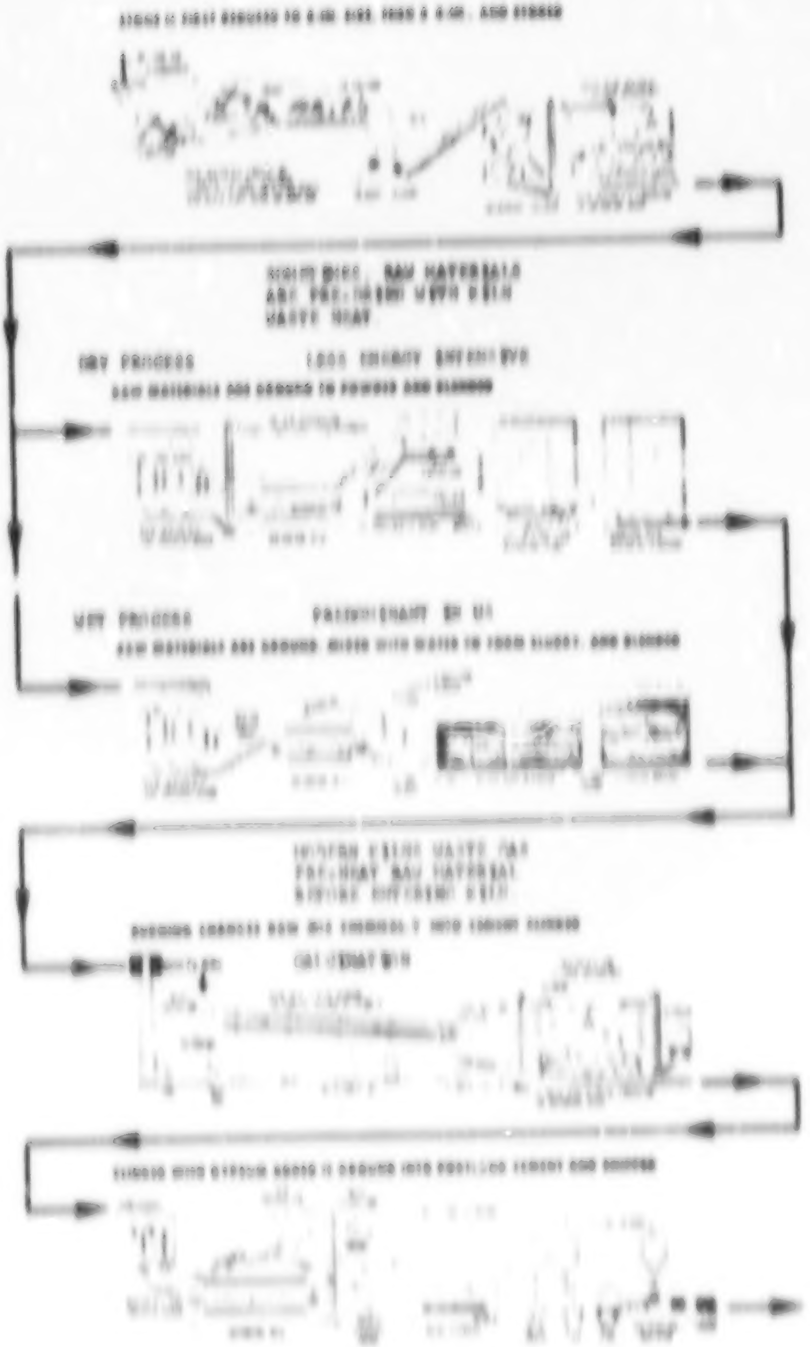

DRY PROCESS
WET PROCESS

Figure 26. Cement process.

Coal and natural gas are major sources of fuel for kiln firing with electricity being used for grinding and mixing operations. Kiln energy utilization is given below for two examples of the dry process.

Typical heat recovery techniques of modern plants include:

1. Preheating of incoming raw material with exit gases,
2. Preheating of combustion air with clinker,
3. Drying of raw materials with hot kiln gases.

The average kiln age of the 10 largest cement companies is approximately 20 years, and many kilns are over 40 years old.

Preheater systems have a disadvantage that alkali metal compounds, normally removed in the hot exit gases are condensed on the cold raw mix and reintroduced into the kiln. A cycle is thus set up that can increase alkali metal concentration in the processed clinker. To overcome this, gas bypass systems are used which divert 5 to 10 percent of the gas with the alkali components in vapor. Cooling of this gas from 2,000° F to 800° F condenses these contaminants, and this gas is then used to dry raw materials. The loss of 5 percent of the gas to bypass represents an extra heat consumption of about 130,000 Btu/ton. The processing of limestone and gravel into clinker offers several possible TES applications. At the head of the plant, heat processes form the clinker, which is subsequently ground and processed into the final product. Grinding creates heat in the ground clinker not now recovered. The gas heat recovered/stored in a TES, can supply drying heat for incoming raw charge feed or dry process or preheat combustion air. These applications would most likely benefit older plants devoid of integrated heat recovery equipment.

The clinker cooling pit can be integral to a TES with the resulting recovered heat supplied for any of the already mentioned functions. For those more modern systems which have preheaters to heat incoming raw charges to the kiln and where gases must be periodically bypassed to reduce alkali metal concentration, the bypassed gases can be used to charge a TES, which would then be able to supply additional heat for charge preheating and/or raw material drying.

*Paper manufacture*

Paper manufacture is accomplished in two major steps:

1. Production of pulp (primarily a chemical process.)
2. Refining of pulp into finished paper (a mechanical process).

The basic schematic is shown (fig. 27) with approximate energy levels as indicated in figure 28.

The pulp and paper industry generates two byproducts that are used as fuel for the production of steam: bark and black liquor. Bark must be removed from the logs because of its low fiber value, and it is usually burned in bark boilers. Black liquor is the spent cooking liquor from the digester, a solution of inorganic chemicals (essentially sodium sulfide and caustic soda) and organic matter (lignin). The chemicals are recovered by evaporation, and the organic matter is burned in the recovery furnace producing thereby a substantial share of the mill's steam requirements.

There are several functions that appear to be compatible with basic TES operations capability, the batch digestion function, smelt discharge, and in a paper breaking sequence within the paper mill. An advanced concept using solar energy is shown in figure 29. In addition, several unit processes have potential.

*Batch Digestion.* Wood chips that have been digested with liquor are "blown" into blow tanks from the digester to reduce the pressure from 100 psi and also to aid in breaking the chips into pulp. This material is at 340° F. This is followed by cooling and washing. Also steam is liberated during this "blow." Use of this energy steam liberation and pulp cooling charges a TES. This TES might then be used to preheat an incoming charge, thereby reducing process steam requirements. The restriction is that most new digesters are continuous processors.

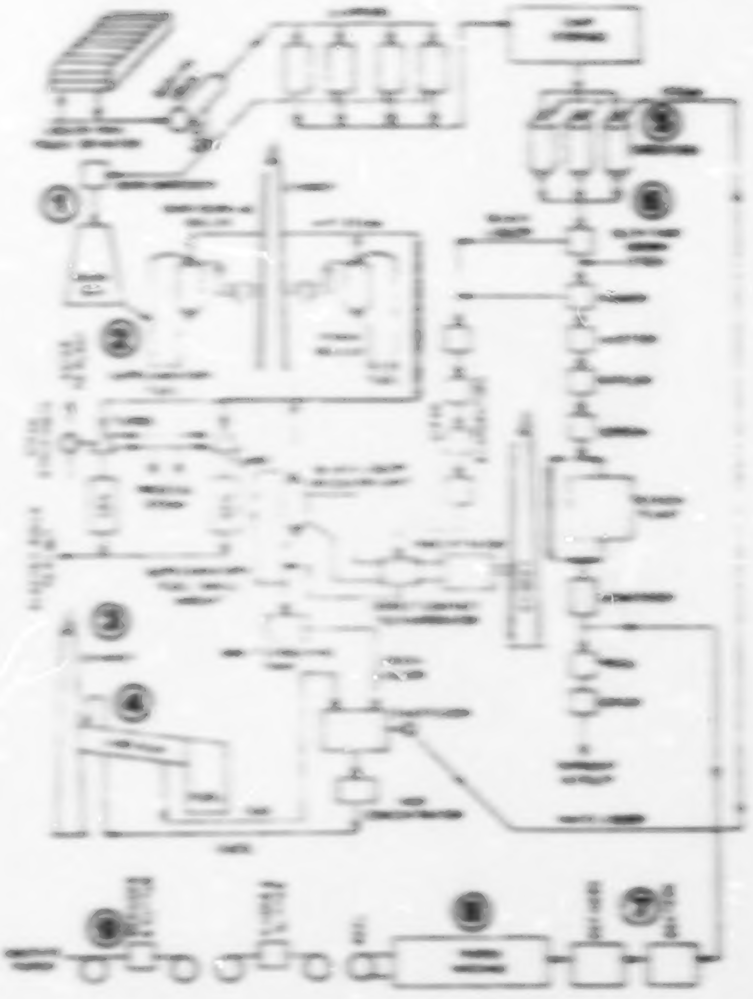
*Smelt Discharge.* Molten char containing recoverable inorganic chemicals is continuously discharged from the black liquor heat recovery furnace. This smelt is then quenched, crushed, and recycled to recover useable chemicals for the digestion process. The char melts at about 1,800° F (1,000° C). Energy from the smelt cooling and/or energy from steam liberated during the quenching operation could be used to charge a TES which would be used for process steam, electrical generation, digester input preheating, etc. The restriction is that smelt withdrawal is a continuous process.

*Paper Breaking in Mill.* When the process paper breaks in a paper machine, a TES could collect the energy normally going to the dryer rolls. This could then be used to preheat the rolls prior to restarting, preheat the digester charge, etc.

*Aluminum*

Aluminum production may be broken down into three steps:

1. Ore mining and preparation,
2. Alumina preparation (Bayer process),
3. Aluminum smelting (Hall process).



1. BARK DRIED TO 50% MOISTURE CONTENT.

2. BARK USED AS FUEL FOR STEAM RAISING.

3. BLACK LIQUOR NEXT SPRAYED ONTO WALL OF BOILER WHERE FURTHER WATER REMOVAL AND FINALLY COMBUSTION TAKES PLACE.

4. SMELT TAPPED FROM FURNACE, QUENCHED AND GROUND TO RECOVER CHEMICALS, WHICH AFTER FURTHER PREPARATION CAN BE RECYCLED INTO THE COOKING PROCESS.

5. STEAM COOKS AT HIGH TEMP & PRESSURE.

6. DIGESTORS
   TEMP ~ 350°F, PRESSURE ~ 150 PSI
   HEAT FROM STEAM
   BATCH PROCESS & CONTINUOUS PROCESS

7. PULP IS PASSED BETWEEN TWO RUBBING SURFACES.

8. MECHANICAL WATER REMOVAL, ROLLERS & PRESSES
   DRYERS — LARGE DIAMETER HOLLOW ROLLS, HEATED WITH STEAM
   CALENDAR MACHINES — COMPRESS PAPER TO GIVE IT A SMOOTH FINISH. COLORING MAY BE ADDED IN WHICH CASE PAPER IS WETTED UP TO 20%, AFTER THAT, IS DRIED IN AFTER DRYERS SIMILAR TO INITIAL DRYING MACHINES.

9. TRIMMING & CUTTING OPERATIONS ON SURFACES.

Figure 27. Pulp-paper manufacturing operation.

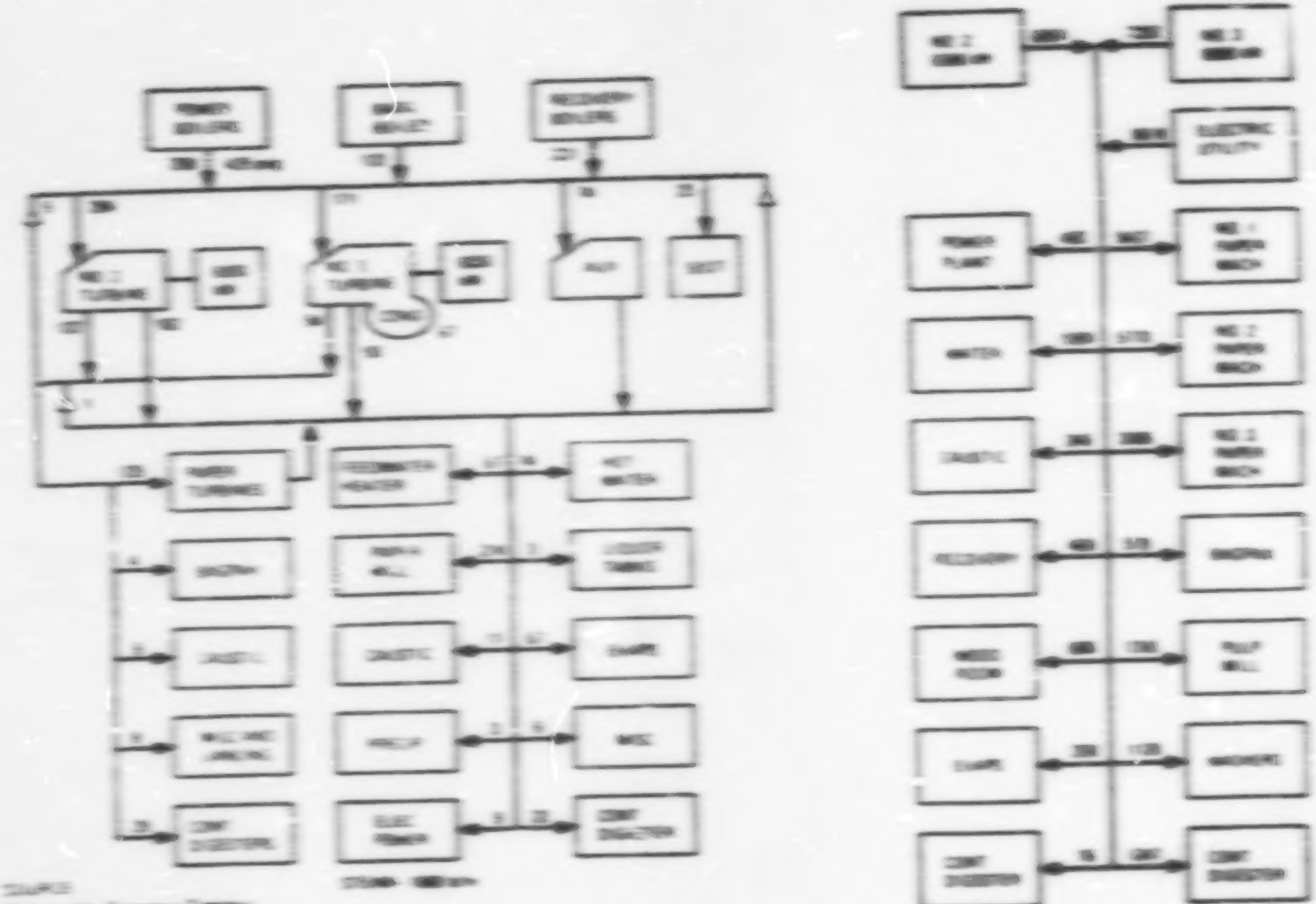


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Figure 28. Steam and electric power flow diagram in integrated paper mill.

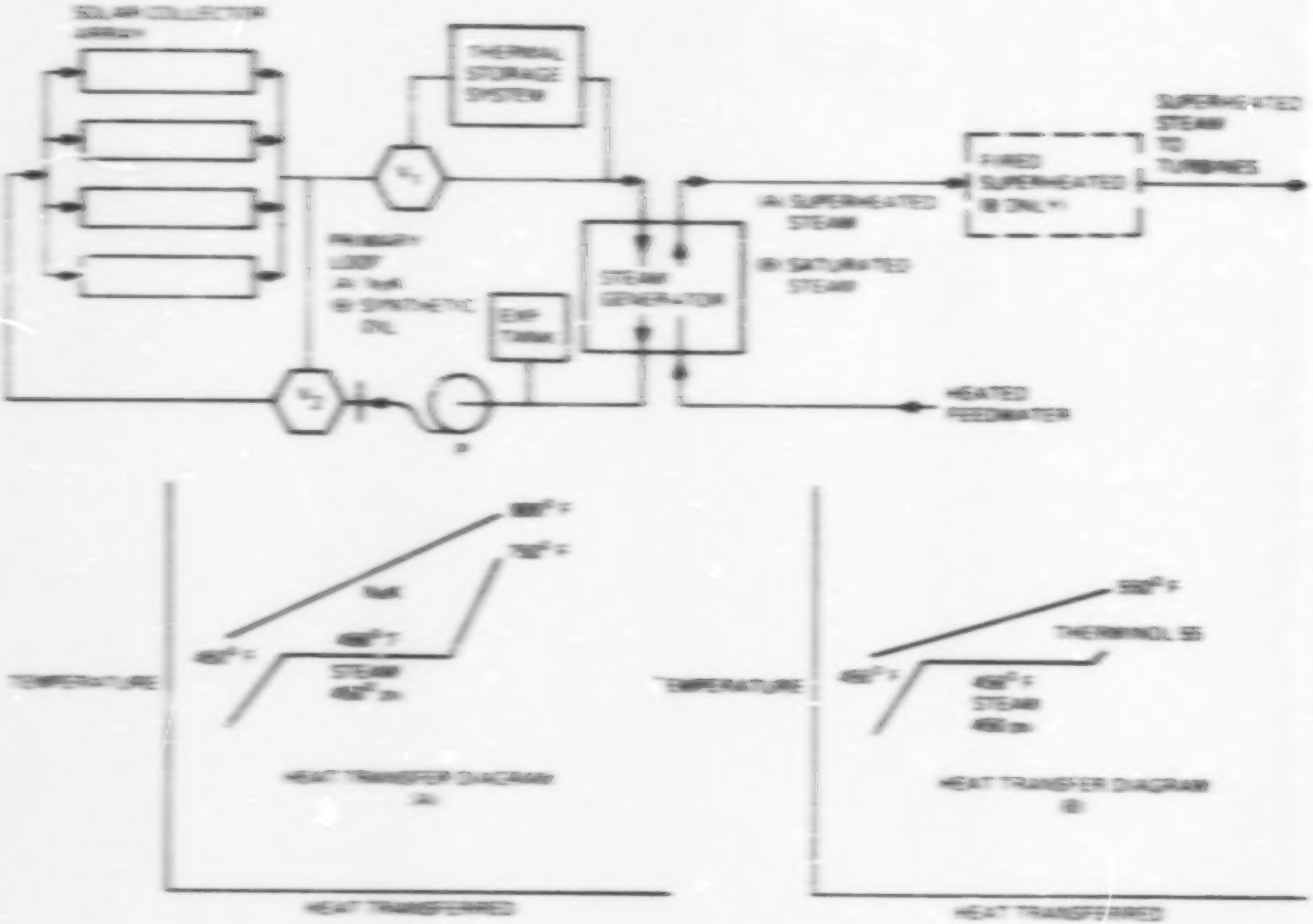

SOLAR COLLECTOR ARRAY
THERMAL STORAGE SYSTEM
PRIMARY LOOP
(A) TAR
(B) SYNTHETIC OIL
EXP TANK
STEAM GENERATOR
(A) SUPERHEATED STEAM
(B) SATURATED STEAM
FIRED SUPERHEATER (B ONLY)
SUPERHEATED STEAM TO TURBINES
HEATED FEEDWATER
TEMPERATURE
STEAM
HEAT TRANSFER DIAGRAM
(A)
HEAT TRANSFERRED
TEMPERATURE
THERMINOL 55
STEAM
HEAT TRANSFER DIAGRAM
(B)
HEAT TRANSFERRED

Figure 28. Solar energy systems for pulp-paper industry steam generation.

Only 15 percent of the required bauxite ore is obtained domestically. Also, since the domestic supplies that are available must be shipped long distances, it is usual practice to dry the ore at the mine to reduce shipping costs. Therefore, even though a rotary kiln at 1,100° F is used for drying, the waste energy is not available for later processes.

In the Bayer process, ground bauxite is digested with a caustic soda solution in steam-jacketed containers at 300° F and 50 to 70 psi for 2-8 hours. The sodium aluminate is cooled and pumped to precipitators where alumina hydrate crystals are formed. The crystals are then heated in kilns at 1,800° to 2,200° F to produce alumina.

The Hall process is an electrolytic reduction process where alumina is continuously dissolved in molten cryolite in a reduction cell. Aluminum is liberated and sinks to the cathode while oxygen goes to the anode, which it attacks, burning to CO and then to $CO_2$ with contact to air. The low voltage direct current cell operates at about 1,700° F.

Two anode systems are used, prebaked electrodes (fig. 30) and continuous Soderberg eletrode (fig. 31). The Soderberg system uses an anode which is baked by the reaction heat of the cell.

The finished aluminum is tapped off from the cell, or siphoned out, and then poured into preheated crucibles. From there it is either cast into ingots or alloyed for further processing.

Though more modern plants are highly engineered for energy efficiency, several possible TES applications are recognized.

***Bauxite Drying***. Steam driven off during the drying step could be used to charge a TES and then later used for further processing (assuming plant is located near the mine), preheating of incoming charge, or space heating, as required. After ore has been dried, the heat content of the still hot ore could be used to charge a TES which would then be used for the same functions as above.

***Bayer Process***. Energy is captured from steam given off in rotary kiln and is used to provide steam for digester, to generate electricity, and/or to use in the carbon electrode baking process. This process may be employed to capture energy from hot alumina, which has the same uses as for Bauxite Drying.

***Auxiliary Processes***. These are:

1. Evaporation of spent liquor to recover energy from vapor driven off.
2. Red Mud Kiln for the recovery of energy from cooling process.

***Hall Process***. This process is for the cooling of castings and ingots. This energy is routed to TES, which could then be used to preheat crucibles.

***Prebaked Electrodes***. These are used to:

1. Recover energy from kiln baking in the form of steam.
2. Recover energy from kiln cooling.

### *Petroleum*

Petroleum refining utilizes most of the raw energy as direct heat (combustion operations) followed by extensive reclamation and reuse of waste heat in a cascading series of thermal process functions. Common to all refineries are the process temperatures required for cracking, distilling, and reforming functions to produce the derivative petrochemical products of crude oil. Unfortunately, process and equipment designs are as numerous (individualized) as there are U.S. refineries (247 in 1972). A general schematic of the most prevalent process is shown (fig. 32). Refineries are located near or on sites where oil availability is abundant. Little electricity is required in the process, but natural gas for future and some reformers is increasingly harder to obtain. Temperatures and pressures for major energy-consuming processes are shown on the above diagram (fig. 32). Operations (called "crude runs") are continuous for as long as certain fuel stocks (grades) are being produced. The need to produce, say, jet fuel after a run of heating oil requires a plant shutdown and redirecting of certain crude process parameters, crackers, and distillation operations to restart the refining for the new product. As there are many different refining designs, additional analysis of unit processes is needed to develop any potentials for solar thermal applications; however, large amounts of steam and middle high temperature (600° to 1,000° F) heat processes are characteristic of the process train.

### *Automobiles*

Auto production involves many energy-consuming processes including casting, forging, machining, molding, painting, paint baking, etc. The metals included are steel, copper, aluminum, and cast iron; nonmetals include rubber, plastics, vinyl, and textiles. A total energy accountability would show the total energy consumed from raw materials to final assembly to be as shown (table 15) using 1974 basis and considering three sizes and weights of cars.

The operations implicit in the manufacture of the many products assembled into a modern automobile must be investigated in that a wide variety of heat functions are utilized. The summary of industry groups

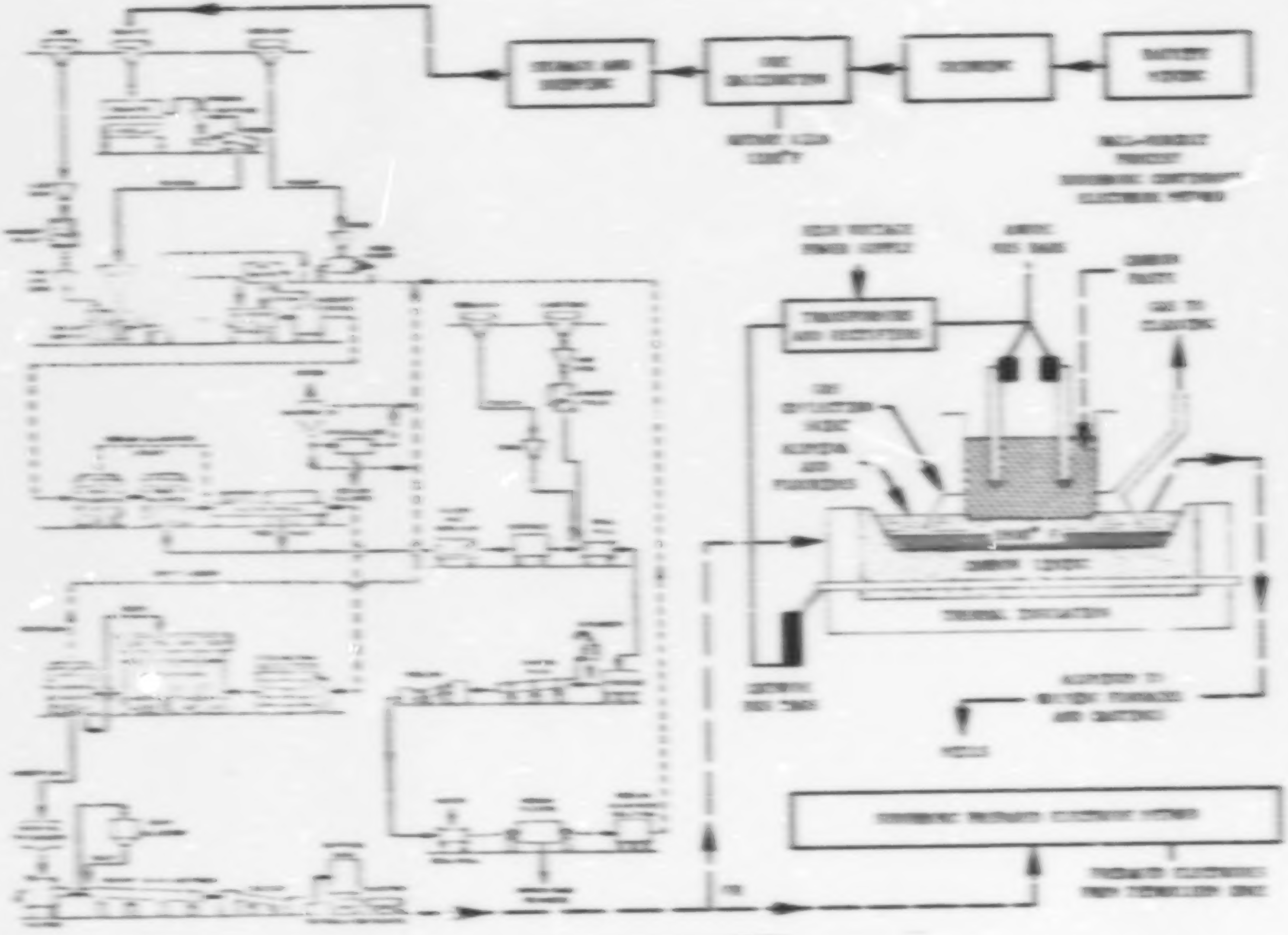
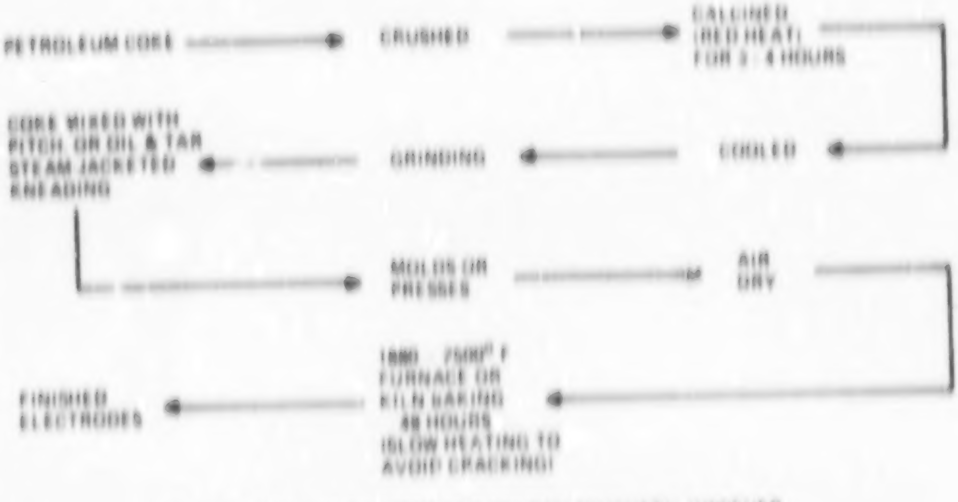


Figure 33. Alumina reduction cell Soderberg system.


PETROLEUM COKE
CRUSHED
CALCINED (RED HEAT) FOR 3 - 4 HOURS
COOLED
GRINDING
COKE MIXED WITH PITCH OR OIL & TAR STEAM JACKETED KNEADING
MOLDS OR PRESSES
AIR DRY
1800 - 2500° F FURNACE OR KILN BAKING 48 HOURS (SLOW HEATING TO AVOID CRACKING)
FINISHED ELECTRODES

(OLDER KILNS NOT EQUIPPED FOR ENERGY RECOVERY. HOWEVER MORE MODERN KILNS ARE NET PRODUCERS OF ENERGY (AS STEAM))

Figure 31. Prebaked electrode process.

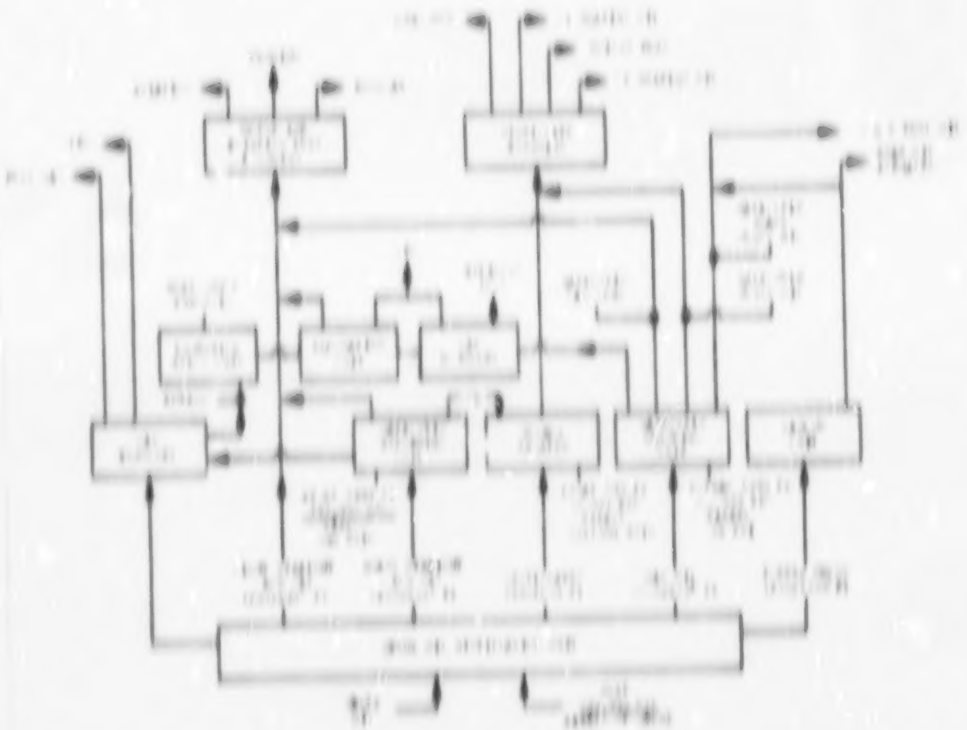


Figure 32. Sample petroleum industry.

## Table 15. Automobile material breakdown and energy for manufacture

| Materials Group | | 1974 Plymouth Valiant<br>4-Dr Sedan, 225 CID engine, Auto trans, pwr steer, pwr brakes, radio & heater Curb Wt 3211 lb | | | 1974 Plymouth Satellite<br>4-Dr Sedan, 318 CID engine, Auto trans, pwr steer, pwr brakes, radio & heater Curb Wt 3617 lb | | | 1974 Plymouth Fury III<br>4-Dr Sedan, 360 CID engine, Auto trans, pwr steer, pwr brakes, radio & heater Curb Wt 4215 lb | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Energy BTU/lb (Table 3) | Lbs/Car | BTU/Car (Thousands) | Bbls crude oil/Car | Lbs/Car | BTU/Car (Thousands) | Bbls crude oil/Car | Lbs/Car | BTU/Car (Thousands) | Bbls crude oil/Car |
| Plain Carbon Steel | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| Stainless Steel | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| Alloy Steel | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| Galvanized Steel | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| Aluminized Steel | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| Cast Iron | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| Nodular Iron | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| Malleable Iron | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| Aluminum, rolled-extrusions | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| Aluminum, cast | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| Copper & copper alloys | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| Zinc, cast | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| Lead | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| Body Solder | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| Glass | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| Rubber | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| Plastics | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| Soft Trim | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| Sound Deadeners & sealers | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| Paint & protective dip | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| Fluids and lubricants | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| TOTALS | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |

Presentation by Daniel A. [illegible], Vehicle Emissions Planning, Product Planning and Development Office, Chrysler Corporation, at Energy Seminar conducted under the auspices of Institute of Science and Technology, University of Michigan at [illegible], August 22, 1974 in Traverse City, Michigan.

whose products support the overall manufacture and assembly of end items, such as autos, represents the five largest energy users. Consequently, only the assembly and finishing operations are unique to this manufacturing process. These represent 26 percent of the total energy required, a significant portion. Included in the 26 percent figure are plating, paint baking, various corrosion-preventing dipping operations, and support systems. A further investigation of these operations is warranted for possible TES applications.

*Conclusions*

The potentials for TES in industry can be categorized as basically relating to steam systems with the highly variable demands and heat supply for process functions spanning the entire spectrum of industrial temperatures. Major challenges lie in materials compatibility of TES media and containment, heat exchange, and monitoring/controlling the system with respect to the heat capacity of the store and dynamics of heat flow on a demand basis.

Several industrial applications are apparent, a few having nearer-term potentials, most requiring new technical innovations both to current process equipment and in creating means for capturing, exchanging, and storing the vast amounts of high-temperature reject heats of heavy industry.

## ACKNOWLEDGMENTS

The author wishes to thank the members of the GE Thermal Energy Storage project team, particularly Robert McCarthy, John Schelkopf and Tom Gresko, and Dr. Philip Lowe and C. J. Swet, Thermal Energy Storage Program Management of the Energy Research and Development Administration, Washington, D.C., for their guidance and support on the basic program. The major portion of the materials reported in this paper are the result of an ongoing program funded by ERDA (contract No. E(11-1)-2558).

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# ENERGY CONSERVATION BY THE RENOVATION OF HIGH-TEMPERATURE TEXTILE WASTEWATER

Craig A. Brandon, Ph.D.[1]

## *Abstract*

*Hyperfiltration has previously been shown effective in the renovation of textile dyeing and finishing wastewaters for direct recycle at full process temperature. Direct recycle achieves conservation of resources, which is an ideal form of pollution abatement.*

*The objective of the research program at Clemson University is to assess the potential impact of the application of high-temperature hyperfiltration technology on energy conservation and environmental preservation. This objective includes the determination of the practicality of this application, i.e., the cost effectiveness.*

*The largest single use of energy in the textile industry is for dyeing and finishing—about 4.1 x $10^6$ gallons of fuel oil per day (equivalent). The potential energy conservation benefit to be realized by full utilization of direct recycle at process temperature is estimated to be about 2 x $10^6$ gallons of fuel oil per day (equivalent).*

*The description of the high-temperature hyperfiltration research program is presented by way of a brief discussion of preliminary results for two examples. One example of a batch-type process and one example of a continuous process is presented. These two categories of processes each represent about half the production in the textile industry.*

## INTRODUCTION

Hyperfiltration has been shown effective in the renovation of textile dyeing and finishing wastewaters for direct recycle at full process temperatures (ref. 1). Of course, such direct recycle, while achieving conservation, is also an ideal form of pollution abatement.

The objective of the research at Clemson University† is to assess the potential impact of the application of high-temperature hyperfiltration technology on energy conservation and environmental preservation. Our objectives include the determination of the practicality of this application, i.e., the cost effectiveness.

The textile industry utilizes about 2.8 percent of the industrial energy consumed in the United States (ref. 2). About 70 percent of the energy used in the textile industry is provided by fossil fuels. The largest single use of energy is in dyeing and finishing; about 4.1 x $10^6$ gallons of fuel oil per day, or its equivalent.

Without conservation, the energy use in the industry will increase by at least 30 percent in the next 4 years. By way of reference, this will be about 10 to 15 percent of the flow of the Alaskan pipeline.

The effluent from the wet processing of textiles constitutes more than a minor industrial waste stream. A recent study (ref. 3) concludes that over the next decade the daily discharge of textile wastes will be nearly constant at about 1 billion gallons per day. The constancy is a consequence of anticipated improvements in finishing processes and not in a fixed fiber usage. The potential pollutional load on the environment of the textile waste stream is considerable, since the biological oxygen demand is about 600 mg/l. About three million pounds of dissolved solids are included in the daily waste stream. In addition, the textile effluent may produce an esthetically unacceptable coloration of the receiving waters.

This paper presents a description of the high-temperature hyperfiltration research program by way of a brief discussion of preliminary results for two examples. One example of a batch-type process and one example of a continuous process are presented. These two categories of processes each represent about half the production in the textile industry. The results presented are preliminary since this program was initiated on July 30, 1975.

## ECONOMIC POTENTIAL OF REUSE

The use of dynamic membrane hyperfiltration to effect energy conservation by renovation of hot process effluents for direct recycle was suggested in 1971 (ref. 4). The waste streams, i.e., process effluents, are in fact relatively dilute mixtures of residual chemicals in the originally "pure" process water. The water and the chemicals each are an operating cost of the textile process. The treatment of the effluent is an increasingly significant additional cost as discharge requirements become more stringent.

The economic potential of reuse of the constituents in the composite waste stream from a textile dyeing

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†Research sponsored by EPA Grant No. R803975.

plant is illustrated by the following values for the contents of a 2 x $10^6$ gallons/day (7,570 $m^3$/day) waste stream:

| Constituent | Value ($/day) |
|---|---|
| Chemicals @ 4.4 ct/kg<br>(@2 ct/pound) | 500 |
| Water @ 13 ct/m<br>(@ 50 ct/1,000 gallons) | 1,000 |
| Heat @ 1.9 ct/$10^7$ J<br>(@$ 2/$10^6$ Btu) | 857 |
| Total | 2,357 |

These values are directly proportional to the volume of the waste stream. The total dollar value for the billion gallon (3.8 x $10^6$ $m^3$) daily discharge estimated for the textile industry is nearly $1.2 x $10^6$/day. In the current era of rapidly rising prices, this may be a conservative estimate.

Full recovery of the potential value of the solids undoubtedly presents the greatest difficulties. However, if only the NaCl salt is reused, e.g., with acid and direct dyeing operations, the wasted chemicals in the effluent represent a significant economic loss.

The economic potential of reuse is enhanced for direct recycle of the effluent from individual processes. In particular, the energy conservation achieved by direct recycle at full process temperature is optimum, and the recovery of chemicals may be less difficult, when only a simple concentration is required.

Before presenting the preliminary results for the two examples, a brief description of the hyperfiltration process with dynamic membranes, and of two related research programs will be given for completeness.

## HYPERFILTRATION

Hyperfiltration, or reverse osmosis, is a separation process (ref. 5) involving the filtering of aqueous solutions by membranes capable of removing not only suspended particles but also substantial fractions of dissolved impurities, including organic and inorganic material. The process is illustrated schematically in figure 1. Application of high pressure to the feed solution causes purified product water to pass through the membrane. The remaining feed becomes a concentrated solution.

Dynamic membranes, which are formed by deposition of materials from the circulation feed stream onto a suitable porous support, may be formed from waste constituents themselves or from certain polyelectrolytes (ref. 6). The previous dye waste tests (ref. 7) were made both with self-formed membranes and preformed dual-layer hydrous Zr(IV) oxide-polyacrylate membranes (ref. 8). The preformed membranes, which are usually superior in both solute rejection and purified water production rate, will be used with the process effluents in the present program.

The performance of dynamic membranes is characterized by high product flux, of the order of 50 to 100 gallons per day per square foot and good solute rejection, of the order of 70 to 95 percent.

In addition, dynamic membranes have the characteristic of a stable positive performance coefficient with temperature. This capacity to treat high-temperature wastewater is not possessed by present-day commercial cellulose acetate and polyamide membranes.

The present program is related to two other projects that will be described briefly.

## RELATED PROGRAMS

### *Pilot Plant Demonstration*

In 1972 the potential savings were recognized by EPA (Grant No. S800929) and industry. A pilot plant demonstration of hyperfiltration treatment of composite wastewater from a typical textile dyeing and finishing plant was sponsored at La France Industries, a division of Riegel Textiles (ref. 9).

Even though 32 becks were exhausted to a common drain, both the purified product water and the concentrated residue were recycled in 18 full-scale production dyeings that produced 1,000 m of furniture and upholstery fabrics (ref. 10). Even though it was thought that such a mixture may only be useful for dyeing black, eight standard shades were processed and sold as parts of "first quality" commercial orders. In table 1, the amount of dyes that would have been used to achieve the standard shade is compared to the amount of dye used in the test dyeings. On the average, 18 percent savings in dyes were observed.

### *Mobile Demonstration*

As a result of this pilot plant, a mobile laboratory demonstration project was initiated (EPA Grant No. S802973) to the South Carolina Textile Manufacturers Association. Table 2 indicates some of the characteristics of the 12 different plants involved in this program. The major types of fibers and processes were included in this survey program. The plant size is indicated by the discharge that ranged from 2,700 $m^3$/day (0.7 MGD) to 45,400 $m^3$/day (12 MGD). The range of chemical characteristics and pollutional loading is indicated. The flow-weighted average solids loading, 1,900 mg/l, indicated in table 2, is over three times the industrywide average of 600 mg/l given by Porter (ref. 3) earlier.

This mobile demonstration was necessary because field test evaluations of membranes are essential to obtain meaningful design data. It is also important that the

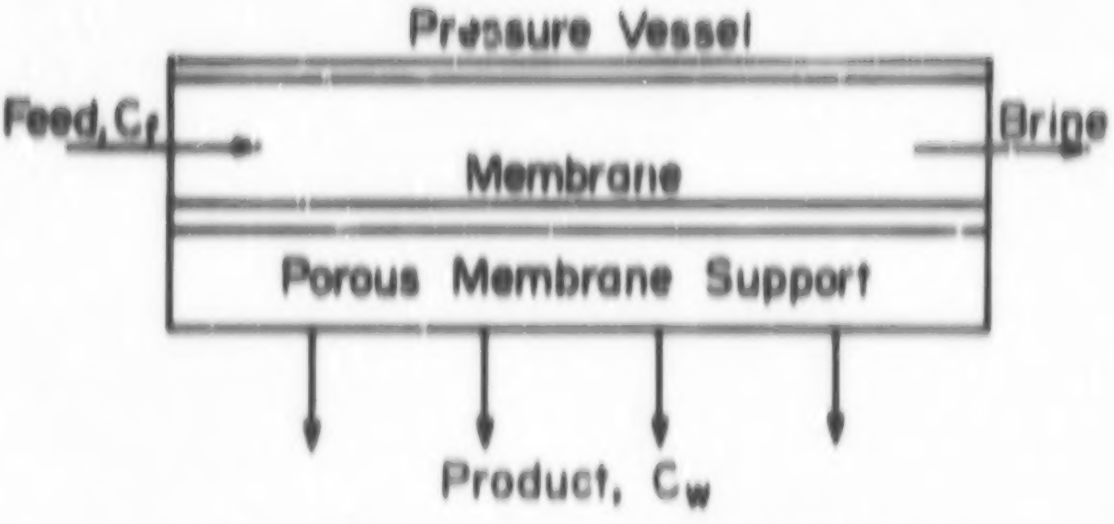
Pressure Vessel
Feed, $C_f$
Brine
Membrane
Porous Membrane Support
Product, $C_w$

Figure 1. Schematic diagram of hyperfiltration membrane.

Table 1. Reuse dyeings of cotton velour with concentrate water[a]

| Weight of fabric (lb) | (kg) | Shade | Number of dyes<br>Reuse test | <br>Standard formula | Amount of dyes (percent of fabric weight)<br>Reuse test | <br>Standard formula |
|---|---|---|---|---|---|---|
| 48 | 22 | Tan | 3 | 4 | 0.417 | 0.438 |
| 97 | 44 | Blue-green | 2 | 2 | 10.480 | 0.932 |
| 82 | 37 | Light blue | 1 | 3 | 0.055 | 0.189 |
| 86 | 39 | Rose | 3 | 3 | 0.233 | 0.302 |
| 82 | 37 | Violet | 2 | 2 | 0.130 | 0.130 |
| 197 | 90 | Tan | 3 | 4 | 0.305 | 0.438 |
| 153 | 70 | Rose | 3 | 3 | 0.310 | 0.189 |
| 100 | 45 | Blue-green | 2 | 3 | 0.485 | 0.632 |
| 52 | 24 | Burnt-orange | 3 | 3 | 1.450 | 1.940 |
| 157 | 71 | Gold | 4 | 3 | 0.990 | 1.033 |

[a] EPA Grant No. 5800929.

Table 2. Characteristics of textile effluents in mobile hyperfiltration project[a]

| Fibers processed (percent) | | | Waste discharge characteristics | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | Flow | | Temperature | | pH | COD | TDS |
| Cottons | Synthetics | Wool | $10^3$ GPD | $10^3$ $m^3/d$ | °F | °C | | (mg/L) | (mg/L) |
| X | X | | 3.0 | 11.4 | 107 | 42 | 9.8 | 1284 | na |
| | X | | 0.7 | 2.7 | 100 | 38 | 4.0 | na | 435 |
| X | X | | 2.0 | 7.6 | 110 | 43 | 11.0 | 2400 | 3600 |
| X | X | | 8.3 | 31.4 | 99 | 38 | 11.4 | na | 1850 |
| X | X | | 4.8 | 18.2 | 88 | 31 | 11.2 | 890 | 980 |
| X | X | | 12.0 | 45.4 | 120 | 49 | 11.0 | 1780 | 1750 |
| X | X | X | 2.0 | 7.6 | 91 | 33 | 7.3 | 670 | 1130 |
| X | X | X | 6.0 | 22.7 | 81 | 27 | 11.6 | 1033 | 2570 |
| X | X | | 1.4 | 5.3 | 84 | 29 | 11.3 | na | na |
| X | X | | 6.0 | 22.7 | 95 | 35 | 12.4 | 1290 | 3000 |
| X | X | | 1.0 | 3.8 | 130 | 54 | 4.0 | 700 | 800 |
| X | X | | 2.4 | 9.1 | 142 | 61 | 7.0 | 450 | 350 |

[a] EPA Grant No. S802973.

cooperative efforts with the industrial personnel involve the evaluation of recycle in their own laboratories and production facilities.

The organization of the mobile demonstration program is shown in figure 2. The diagram indicates the cooperation between government agencies and industry; between equipment manufacturers and users; and the central role of the university and trade association. This is the same organization for the current energy conservation program except that the EPA grant is directly to Clemson University.

The pilot plant and mobile laboratory programs approached the recovery problem as indicated in figure 3. The composite wastewater from the entire plant was processed by hyperfiltration to achieve recovery. However, since the objective is to separate the mixture for recycle, this separation should be achieved before any unnecessary mixing occurs. Hence, the approach for the current research is to use a hyperfilter for each unit process as indicated in figure 4.

It is typical in the textile industry that the higher temperature effluents are the more polluted with residual chemicals. The preparation, the dyeing, and the finishing of fabrics often is carried out at high temperature. The initial discharge of spent process fluid and the initial wash water are the most concentrated in chemicals. The maximum return of energy and chemicals is from treatment of these hot initial process effluents.

It is interesting to recall that the performance of dynamic membranes is improved at high temperature. Thus, the unusual situation occurs that the maximum potential recovery coincides when the membrane costs are minimum.

Consequently, the current program will evaluate the energy conservation potential by hyperfiltration of the high temperature effluents of unit textile processes for direct recycle.

## ENERGY CONSERVATION PROGRAM

The objectives of this program are to demonstrate the direct recycle of hot textile process waters renovated by high temperature hyperfiltration. The energy conservation and engineering performance details will be assessed for selected unit manufacturing processes.

The objectives will be met by detailed evaluations of selected manufacturing processes in current production operations. The evaluations will be carried out in the following steps:

1. Plant visits for gathering information on details of energy, water, and chemical discharge;
2. Assessment of conservation potential based on field data and laboratory hyperfiltration of wastewater samples;
3. Onsite demonstration of the performance of hyperfiltration on selected manufacturing processes, one batch and one continuous, to obtain engineering design data; and
4. Modification of the manufacturing process will be considered and evaluated within the textile plant facilities.

The results of the assessments for these selected manufacturing processes will provide the engineering data needed for a full-scale demonstration. Ultimately, the demonstration may include the modifications to the textile processes and the application of advanced treatment technology to approach zero discharge.

The following discussion of the two examples includes only the description of the process and the assessment of the conservation potential.

*Batch Process*

The batch process selected for this study involves the piece dyeing of upholstery fabric in large open becks, or atmospheric becks, figure 5. The piece of

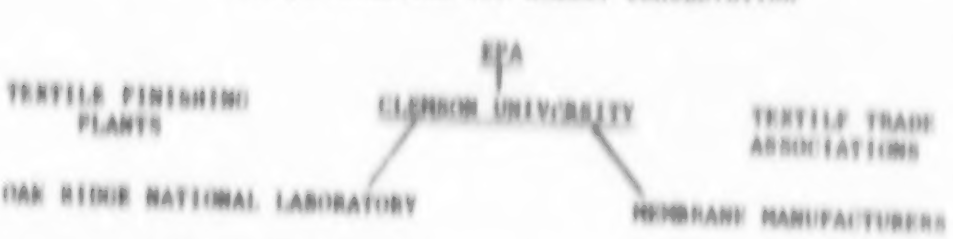
HYPERFILTRATION FOR ENERGY CONSERVATION
EPA
TEXTILE FINISHING PLANTS
CLEMSON UNIVERSITY
TEXTILE TRADE ASSOCIATIONS
OAK RIDGE NATIONAL LABORATORY
MEMBRANE MANUFACTURERS

Figure 2. Organization of cooperative textile research.

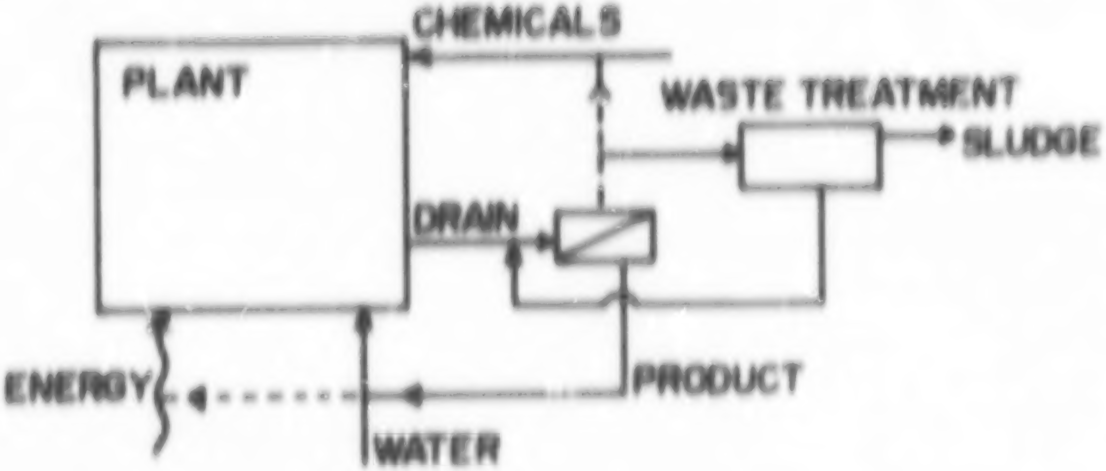
CHEMICALS
PLANT
WASTE TREATMENT
SLUDGE
DRAIN
ENERGY
PRODUCT
WATER

Figure 3. Schematic diagram of renovation of plant composite wastewater.

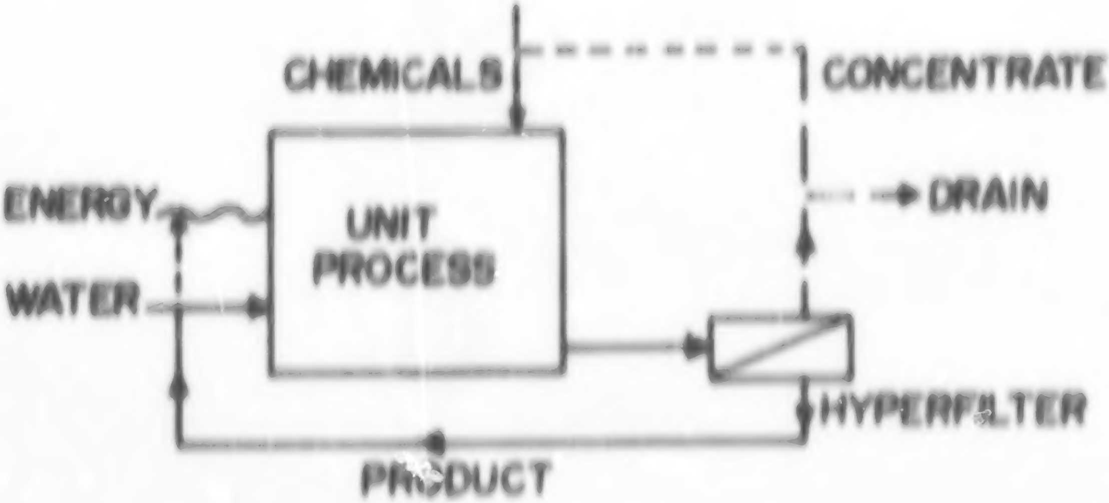
CHEMICALS
CONCENTRATE
ENERGY
UNIT PROCESS
DRAIN
WATER
HYPERFILTER
PRODUCT

Figure 4. Schematic diagram of renovation of unit process effluent.

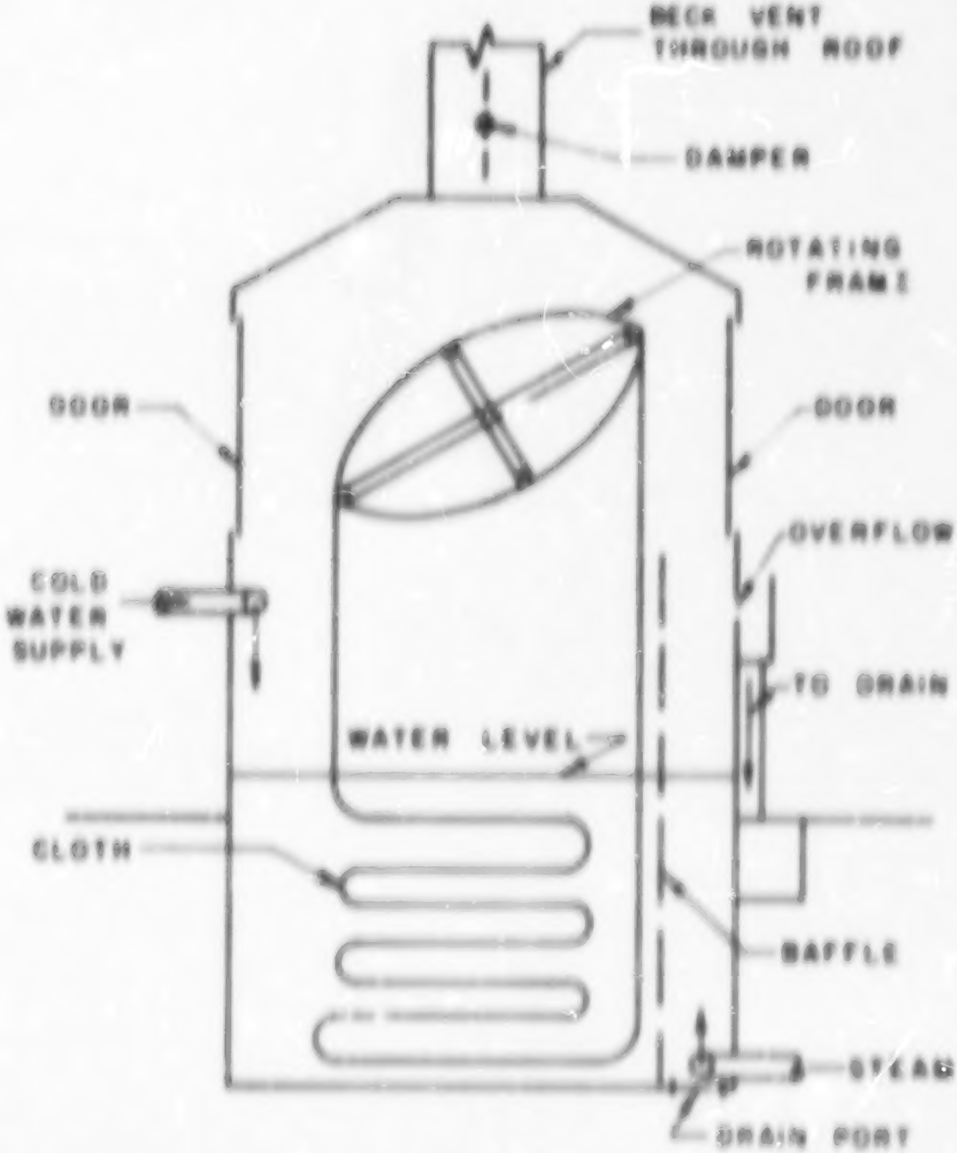
BECK VENT
THROUGH ROOF
DAMPER
ROTATING
FRAME
DOOR
DOOR
OVERFLOW
COLD
WATER
SUPPLY
TO DRAIN
WATER LEVEL
CLOTH
BAFFLE
STEAM
DRAIN PORT

Figure 5. Batch process atmospheric dye beck.

cloth (1,50 m to 600 m in length) is caused to circulate through the bath of chemicals by rotation of the oblong frame in the centre of the machine.

The finishing operation may contain three periods of high temperature operation. The cloth is introduced into the beck after the initial charge of cold water is heated to about 32° C (90° F). The water is further heated, by the submerged introduction of steam, to 60° C (140° F). Chemicals are added to scour the cloth (a stripping step required for approximately 30 percent of the plant production), and the temperature is raised to 74° C (165° F). After about 45 minutes, the water is terminated by the introduction of cold process water. The cooling is accomplished by the dilution and overflow of the chemical bath.

The resulting cold water bath is heated to 49° C (120° F) prior to the addition of dyeing chemicals. The temperature is then elevated and maintained in the range of 91° to 96° C (195° to 205° F) for 4 to 12 hours. The shade being dyed is a principal factor in determining the length of the exposure at temperature. After the desired shade is obtained, the cooling cycle is achieved by the dilution and overflow with cold process water.

Significant amounts of energy are utilized to heat the cold process water during the scouring and dyeing operations. In this plant about 200 million Btu/day are effectively discarded as hot water. Interestingly, in this case it was determined that an even larger quantity of energy is lost as vapor discharged by the forced draft ventilation system. (Attention has been given to minimizing the volume of this draft by closing the access doors to the back.)

The potential for conservation through hyperfiltration is being assessed. By modification of the manufacturing process, it may be possible to carry out the entire operation at about 74° C (165° F). Recycled hyperfiltration permeate can be utilized to wash the cloth. It thus would be necessary only to heat the dye bath from 74° C (165° F) to 91° C (195° F).

Chemical recovery may be achieved by recycle of the concentrate. In particular, it may be possible to recycle the scouring chemicals. The salt used with direct dyes also is a potentially practical recycle (ref. 3).

### *Continuous Process*

The continuous process is shown diagrammatically in figure 6. This process continuously prepares cloth for subsequent finishing, i.e., dyeing or printing. A series of chemical baths are each followed by high-temperature washing to "clean" the cloth. The incremental energy discharged is over 250 million Btu/day at a cost of approximately $500/day.

However, the chemical consumption in this process is over $5,000/day. Both the recycle of hot water and chemicals will be investigated. The potential for some reduction in chemical usage by partial recycle of concentrate may result in a significant conservation of materials and reduction in pollutional loading.

## SUMMARY

These examples illustrate the characteristics of the two basic categories of textile wet finishing operations, i.e., batch and continuous processes. The detailed assessment of energy and material conservation for five specific cases will be considered in detail. Estimates of the total impacts for the textile industry have been made.

### *Potential Energy Benefits*

In general, the dyeing and finishing processes are often such that approximately 25 percent of the water is discharged at quite elevated temperatures. The remaining 75 percent is fairly cool wash water. The potential energy benefit to be realized by full utilization of direct recycle at process temperature was estimated assuming that the hot water is only 100° F above the available cold water supply. Often it is much more. The savings for the textile industry is over 2 million gallons of fuel oil per day, or its equivalent.

### *Potential Environmental Benefits*

The direct recycle of waste chemicals and hot water (energy) at the point source obviously is the best possible pollution abatement technique. Though thermal pollution is not often discussed as a major problem for the textile industry, the treatment of high-temperature industrial wastewater is a difficult problem, even when the plants are associated with municipal treatment facilities. Hence, the elimination of heat and materials by recycle has a definite impact on the need and expense of any downstream treatment.

Previous research has concentrated on renovation and reuse of composite wastewater. This program will evaluate hyperfiltration at point sources in order to effect energy conservation through direct recycle of hot process water. Implementation of point source renovations for direct recycle of heat and chemicals will certainly enhance the treatment of the resulting composite wastes relieved of often refractory materials.

The expected results will provide the engineering data needed for a full-scale demonstration of high temperature hyperfiltration. The results of the energy survey, the laboratory, and the onsite tests will permit the design for complete treatment to approach closed cycle operation.

The combination of conservation, energy, water, and chemical, and pollution abatement simultaneously achieved by membranes may make the cost of this technology practical.

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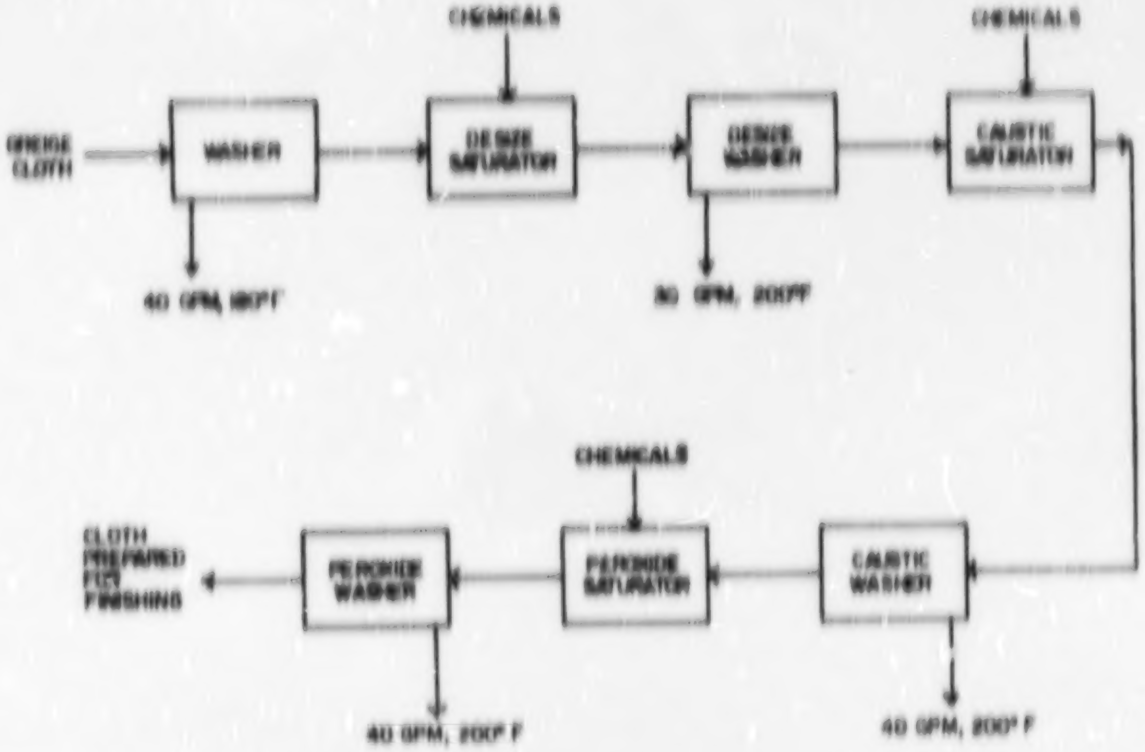
CHEMICALS
CHEMICALS
GREIGE CLOTH
WASHER
DESIZE SATURATOR
DESIZE WASHER
CAUSTIC SATURATOR
40 GPM, 180°F
30 GPM, 200°F
CHEMICALS
CLOTH PREPARED FOR FINISHING
PEROXIDE WASHER
PEROXIDE SATURATOR
CAUSTIC WASHER
40 GPM, 200° F
40 GPM, 200° F

Figure 6. Continuous process preparation range.

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# NEW PROCESSES AND ENERGY CONSERVATION IN THE PRIMARY METALS INDUSTRY

R. H. Cherry, Jr., Ph.D.[1]

*Abstract*

*This paper reports results derived from three recent studies of energy use patterns and requirements in the primary metals industries. These studies were aimed at first categorizing energy and fuel use patterns in 83 metallurgical and related processing areas and, then, evaluating the theoretical potential for energy conservation in seven basic industries.*

*This paper focuses on some of the important results obtained for aluminum and copper in terms of*

1. *energy requirements,*
2. *the potential for energy savings both with and without extensive process modifications, and*
3. *developing or emerging process technology.*

## INTRODUCTION

Battelle-Columbus has been engaged in the assessment and evaluation of process-related environmental, energy, and resource allocation problems for more than 20 years. This paper is based on results derived from selected portions of three recent studies which, in combination, were arrived at by first categorizing energy and fuel-use patterns in 83 metallurgical and related processing areas, and then evaluating the theoretical potential for energy conservation in seven basic industries. These studies are described (in chronological order) very briefly in the following paragraphs.

### *Study of the Energy and Fuel-Use Patterns in the Nonferrous Metals Industries*

This study is one of a series conducted for the Federal Energy Administration (FEA) and the Department of Commerce covering a number of energy-intensive industries (ref. 1). The objective of the program was to develop a preliminary data base in a short time, describing the general patterns of fuel use in the nonferrous metals industry.

For the major SIC's, the information employed in the compilation of the data contained in this report was obtained in part from the literature, but primarily from direct contact with industry representatives. In some cases, excellent responses were received in a relatively short time. In general, smaller companies were found to be in a better position to respond than were large companies.

This study of the patterns of energy use in the nonferrous metals industry included specifically 10 SIC industries categories:

| | |
|---|---|
| 3331 | Primary Copper |
| 3332 | Primary Lead |
| 3333 | Primary Zinc |
| 3334 | Primary Aluminum |
| 3339 | Primary Nonferrous Metals, n.e.c. |
| 3341 | Secondary Nonferrous Metals |
| 3351 | Copper Rolling and Drawing |
| 3352 | Aluminum Rolling and Drawing |
| 3356 | Nonferrous Rolling and Drawing |
| 3357 | Nonferrous Wire, Drawing, and Insulating |

The level of effort applied to each SIC was determined to a degree on the basis of the total energy use in the industry. The primary nonferrous metals, n.e.c., nonferrous rolling and drawing, and nonferrous wire received secondary emphasis on this basis. For example, the analysis of the primary nonferrous metals, n.e.c., industry was restricted to silicon, magnesium, and titanium, the major components of the SIC in terms of production. Data for these metals were obtained entirely from the literature.

It must be strongly emphasized that the results and conclusions of this study were based on a very limited sample of each industry and must be considered as preliminary.

Because of the complexity and breadth of the subject of this paper, we somehow must limit the oral and written presentations to something that is manageable.

This study served to provide background for the broader more complex Bureau of Mines Study (described later). Table 1 gives the estimated total energy consumed for selected SIC's.

Some modest additional background can be injected by appealing to table 2, in which is presented one estimate of the patterns of fuel usage in selected SIC's.

Not surprisingly, this pattern reflects what we know about the structures and operating modes for these kinds of industries. It may serve to point to areas that need attention in order to minimize the dislocations that would be caused by a crunch in energy supply.

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Table 1. Estimated total energy consumed and unit energy factors in the nonferrous metals industries by SIC

| SIC | Industry | Total energy[a] $10^{12}$ Btu 1971 | 1973 | 1974 |
|---|---|---|---|---|
| 3331 | Primary copper | - | 107.3 | - |
| 3334 | Primary aluminum[b] | 620.0 | 590.0 | 639.0 |
| 3351 | Copper, rolling and drawing[c] | 58.2 | 60.2 | 63.4 |
| 3352 | Aluminum, rolling and drawing | 120.3 | 147.2 | 178.9 |
| 3357 | Drawing and insulating of wire | 46.9 | 43.6 | 38.4 |

[a] Expressed as fossil-fuel-equivalent energy.

[b] Values for aluminum assume that 35 percent of electrical energy is hydroelectric.

[c] Data are for only nickel rolling and drawing.

*Evaluation of the Theoretical Potential for Energy Conservation in Seven Basic Industries (ref. 2).*

The objectives of this study were to determine the minimum theoretical energy requirements in seven basic industries through a thermodynamic analysis of the processes employed in each industry. The study includes the steel, copper, aluminum, glass, synthetic rubber, selected plastics, and paper industries. Results of the calculations for these seven industries include the minimum theoretical energy, the efficiency of selected unit processes, and the effect of certain process changes on the energy use.

A computer model was developed to perform the necessary calculations. The model performs the customary energy balances based on the first law of thermodynamics. Availability losses are calculated according to the second law of thermodynamics. The model is general and can be applied to an entire industrial process or to any of the unit operations within the process. The model identifies large energy or availability losses. The model can be operated in an interactive mode so that the net fuel savings, which could be expected to result from changes in operating conditions and procedures or even major process changes, can be computed and displayed in real time. The model is a powerful tool for identifying those operations in which significant fuel savings can be realized through straightforward modifications. In addition, the model will show where the potential for energy conservation is limited by the irreversibilities inherent in the basic processes employed. In the latter case, different, more reversible processes would have to be employed to further reduce energy consumption. Such a definition of the nature of the various availability losses is invaluable in directing the attention of process engineers to those operations that offer the greatest potential for overall fuel savings.

*Energy Use Patterns in Metallurgical and Nonmetallic Mineral Processing (ref. 3).*

Eighty-three commodities were selected as being important basic industrial materials. The detailed energy-use appraisal being performed for these commodities should be of particular value in assessing the national

Table 2. Patterns of fuel use by fuel type by SIC, 1973

| Type of fuel | Percent of total energy consumption | | | | |
|---|---|---|---|---|---|
| | 3334 | 3339 | 3351 | 3352 | 3357 |
| Propane, butane | <1 | - | 2 | <1 | 2 |
| Distillates | <1 | - | 1 | <1 | - |
| Residual oil | - | - | 9 | 7 | 22 |
| Gasoline | <1 | - | <1 | <1 | - |
| Lubricants | <1 | - | 1 | 1 | <1 |
| Miscellaneous petroleum products | - | - | <1 | 4 | 11 |
| Coal | <1 | 22 | 3 | - | - |
| Natural gas | 3 | 22 | 33 | 46 | 12 |
| Coke[a] | 6 | 19 | - | - | - |
| Electrical energy | 91 | 37 | 52 | 41 | 54 |

[a] For primary aluminum this is petroleum coke.

pattern of energy consumption. This study differs from the usual energy analysis in that it includes estimated energy requirements for mining and beneficiation, consumable raw materials, transportation, and fuels and electrical energy.

The analysis of the energy-use patterns for each of the 83 commodities consists of the following components:

1. Concise characterizations of the commodities based on 1973 data;
2. Brief descriptions of the major production processes;
3. Flowsheets, which indicate the major raw materials and unit processes;
4. Estimated energy values for the various unit operations;
5. Notes and references, which clarify important factors and indicate the sources used to develop the tabular data.

The most important facets of commodity characterization may be summarized as follows:

1. The magnitude of imports of ores and concentrates is given. Such imports are of particular significance with regard to energy because, in the mining and beneficiation of ores in which the desirable mineral is present in very small amounts (e.g., nickel ores), a fairly large amount of energy is consumed in producing a net ton of concentrates. The level of such imports also indicates the degree of U.S. dependence on foreign sources for basic raw materials.
2. Imports of partially or completely processed primary product are shown to indicate the extent of reliance on foreign sources, which represent an energy import.
3. Qualitative measures are made to indicate the level of byproduct and coproduct recovery, secondary recovery (from scrap), and the importance of complementary operations.
4. The amount of U.S. production and consumption for 1973 is shown. The consumption tonnage applies only to primary product and does not include consumption of product from secondary (scrap) recovery.
5. The total energy required per net ton of primary product or products is given.
6. The total energy required for 1973 U.S. consumption of primary product or products is shown.

The methodology used to obtain reliable data was a broad-based analysis and evaluation of information available from the following sources:

1. Previous nonproprietary BCL studies on various metals, minerals, and basic industrial commodities;
2. BCL staff who had pertinent industrial experience in production or research;
3. A wide variety of published information related to industrial process descriptions, materials, energy requirements, and statistical data;
4. Wherever possible, energy data for a specific item from several different sources;
5. Discussions with various trade associations for data when available;
6. Discussions concerning energy consumption with representatives of companies producing the various primary products;
7. Review, where possible, of the energy analysis by industry representatives to obtain comments and suggestions;
8. Reviews and discussions with Bureau of Mines staff associated with the study.

The results of the estimation of the total energy requirements (in trillion Btu) for the U.S. consumption of selected commodities permit the ranking as shown in table 3.

The designation H following the estimated energy requirement indicates that the particular commodity was prejudged to have high significance to this study; the designation I indicates an intermediate level of significance.

### Table 3. Ranking by total energy required for U.S. consumption (trillion Btu)

| | | |
|---|---|---|
| *Iron + Steel (All) | 3,770 | H |
| *Aluminum (Ingot) | 1,480 | H |
| Portland Cement | 680 | H |
| Nitrogen (Ammonia) | 586 | H |
| *Copper (All) | 236 | H |
| Glass (Containers) | 216 | H |
| Chlorine (Gas, Liquid) | 199 | H |
| Calcium (Quicklime) | 182 | H |
| Phosphorus (Elemental, Acid) | 147 | H |
| Zinc (Metal) | 92 | H |
| Titanium (Sponge + Oxide) | 78 | I |
| Oxygen (Gas, Liquid) | 73 | I |
| Manganese (Mn, Fe-Mn) | 66 | I |
| Ceramics (Common Brick) | 62 | H |
| Nitrogen (Gas, Liquid) | 48 | H |
| Magnesium (Metal) | 42 | I |

### Table 4. Ranking (continued) by total energy required for U.S. consumption (trillion Btu)

| | |
|---|---|
| Sodium (Na, NaCl) | 39 |
| Nickel (All) | 36 |
| Silicon (Ferro-) | 35 |
| Chromium (Ferro-) | 35 |
| Potassium (Chloride) | 33 |
| Clays (All) | 31 |
| Lead (Refined) | 24 |
| Gypsum (Calcined) | 19 |
| Refractories (Basic Brick) | 18 |
| Refractories (Fireclay Brick) | 7 |
| Uranium (Oxide) | 7 |
| Fluorine (Fluorspar) | 7 |
| Molybdenum (Oxide) | 6 |
| Sulfur (Acid) | 1 |

Table 4 lends some sense of perspective in that the range of estimated energy requirements is displayed; metal commodities have been emphasized.

It is obvious from table 3 that iron and steel, aluminum, and copper head the list of primary metal commodities in terms of energy consumption. As you can see, the specific energy requirement per ton of steel is quite low; the process has been judged (elsewhere) to be relatively efficient. The high energy consumption derives from the fact that the U.S. steel industry in 1973 poured the equivalent of 128 million net tons of steel slab. The manufacture of aluminum ingot represents the highest specific energy requirement.

This presentation focuses on copper and aluminum, each of which is treated as a unit in the following pages. The iron and steel industry, while enormously important, will be treated in subsequent publications.

Studies of the sort reported here require the aggressive support of a number of talented people. The author must consider himself a spokesman for this group. While the author has made (and continues to make) contributions, it is mandatory that the following key Battelle staff members be recognized in terms of the content of this paper (A, B, and C denote department affiliation):

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| Mr. H. N. Conkle (B) | 2486 |
| Mr. D. C. Drennen (A) | 1881 |
| Dr. J. E. Flinn (B) (Project Manager, ref. 1) | 1615 |

Table 5. Energy requirements for the three largest primary metal consumers

| Commodity (product) | Energy required<br>Per net ton, million Btu | Total U.S. consumption, trillion Btu |
|---|---|---|
| Iron + steel | | |
| (Steel slabs) | 24 | 3,350 |
| (Gray iron castings) | 34 | 366 |
| (Steel castings) | 42 | 54 |
| | | 3,770 |
| Aluminum | | |
| (Ingot) | 244 | 1,408 |
| Copper | | |
| (Cement copper) | 87 | 15 |
| (Refined copper) | 112 | 221 |
| | | 236 |

| | |
|---|---|
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| Dr. E. H. Hall (B)<br>(Project Manager, ref. 2) | 1088 |
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| Mr. A. O. Hoffman (A) | 1869 |
| Mr. H. W. Lownie (A) | 2862 |
| Mr. D. J. Maykuth (A) | 2234 |
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## COPPER

### *Estimated Energy Requirements for the Production of Refined Copper*

Table 6 summarizes the production of refined copper. The production of copper is shown schematically in figure 1. The estimated energy requirements (million Btu per ton) are given for each operation.

The commercially important copper ores are sulfides of copper, copper-molybdenum, copper-zinc, and copper-lead-zinc. Most ores contain small quantities of silver, gold, platinum, selenium, and tellurium, which are recovered as byproducts. Mined ore containing less than 0.3 percent copper is deposited in waste rock dumps, from which some copper is recovered by dump leaching. In this study, estimates were based on data for eight open-pit mines. The ore grades ranged from 0.55 percent copper to 0.92 percent copper, and averaged 0.7 percent copper.

In the large open-pit mines, the source of most domestic copper ore, stripping ratios (ratio of waste rock to ore) vary from about 1:1 to as high as 12:1. Much of the energy expended in mining is consumed in the excavation and hauling of overburden. In one mine, about 40 million Btu per ton of copper was expended to mine ore

**Table 6. The production of refined copper**

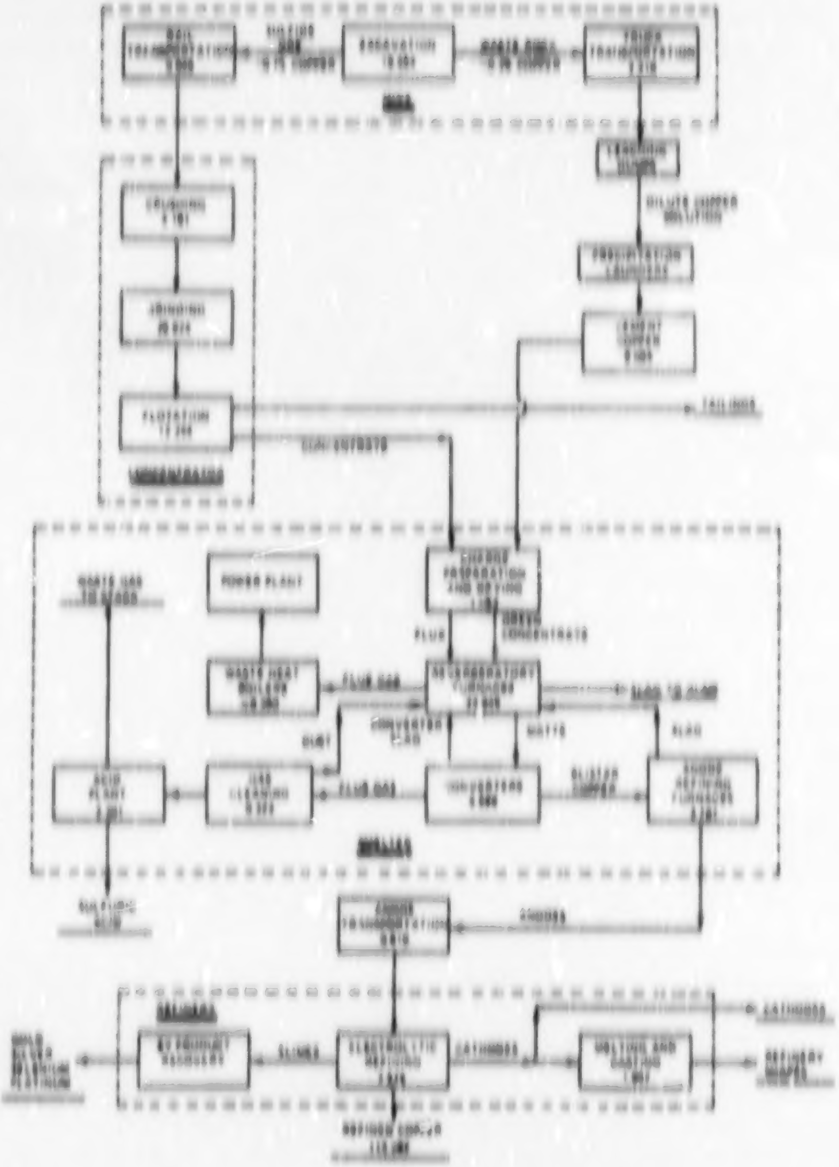
| | |
|---|---|
| Imports | |
| Ore and matte | 42,880 net tons (Cu) |
| Blister and black | 154,101 |
| Refined | 201,611 |
| Byproduct recovery | Silver, gold, platinum, selenium, tellurium, molybdenum, sulfuric acid |
| Secondary recovery (1972) | 465,000 net tons |
| Complementary operations | Production of sulfuric acid is primary means of controlling sulfur emissions; acid used for leaching and sale |
| U.S. production | 1.87 million net tons |
| U.S. consumption | 1.97 million net tons |
| Energy required | |
| per net ton | 112 million Btu |
| for U.S. consumption | 221 trillion Btu |

which averaged 0.7 percent copper at a stripping ratio of 12:1. In another mine, 9 million Btu per ton of copper was expended to mine ore which averaged 0.55 percent copper, but where the stripping ratio was 2.6:1. Explosives consumption was taken as 0.25 pounds per ton of material mined, according to information obtained from two copper producers.

The energy required for truck haulage of ore and overburden and for electric railroad handling was based on published information (ref. 4). These values for hauling represent about 15 percent of the estimated energy consumption in mining. Estimates made by one company indicated that haulage accounts for about 60 percent of the total energy consumed in open-pit mining (ref. 5).

The ore from the mines is sent to the concentrators, which include crushing, grinding, and flotation operations. Kellogg has made a quantitative analysis of the energy required for the milling and flotation of various types and grades of the ores of copper, molybdenum, zinc, lead, and iron (ref. 6). His analysis was based on data published by the Bureau of Mines (ref. 7). Kellogg confirmed that the most significant fact in energy consumption is the grade of ore. Over the years, as the grades of all kinds of ores have decreased, more energy has been needed to extract the mineral values from them. In this study, milling data from three copper companies were analyzed. The energy consumed varied from 38 to 58 million Btu per net ton of copper for an average of 25 million Btu per net ton of copper. This amounts to 60 percent of the average total energy (42 million Btu) used at the concentrator.

The concentrate, which contains about 25 percent copper, is sent to the smelter charge preparation plant, with cement copper produced by leaching and precipitation operations. In most smelters, this mixture is furnace dried before it is charged into reverberatory furnaces. The energy consumed, 24.645 million Btu, is the average of reverberatory furnaces in three different smelters. Two calcine-charge reverberatory furnaces in other smelters were analyzed and found to consume an average of 13.8 million Btu. Roasting operations in three smelt-



RAIL TRANSPORTATION
SULFIDE ORE
EXCAVATION
WASTE ROCK
TRUCK TRANSPORTATION
MINE
LEACHING DUMPS
DILUTE COPPER SOLUTION
PRECIPITATION LAUNDERS
CEMENT COPPER
CRUSHING
GRINDING
FLOTATION
TAILINGS
CONCENTRATE
CONCENTRATOR
WASTE GAS TO STACKS
POWER PLANT
CHARGE PREPARATION AND DRYING
FLUX
GREEN CONCENTRATE
WASTE HEAT BOILERS
FLUE GAS
REVERBERATORY FURNACES
SLAG TO DUMP
CONVERTER SLAG
DUST
MATTE
SLAG
ACID PLANT
GAS CLEANING
FLUE GAS
CONVERTERS
BLISTER COPPER
ANODE REFINING FURNACES
SMELTER
SULFURIC ACID
ANODE TRANSPORTATION
ANODES
REFINERY
CATHODES
GOLD
SILVER
SELENIUM
PLATINUM
BY-PRODUCT RECOVERY
SLIMES
ELECTROLYTIC REFINING
CATHODES
MELTING AND CASTING
REFINERY SHAPES
REFINED COPPER

Figure 1. Production of refined copper by conventional mining and smelting processes.

ers consumed an average of 1.84 million Btu. Exclusive of roasting or drying operations, the calcine reverberatory furnaces consumed about 10 million Btu less than the green-charge reverberatory furnaces. Many other factors, including copper content of the concentrate, heat loss from the furnace, and operating variables, affect the energy consumed in green or calcine reverberatory furnace operations.

In some plants, the concentrate is roasted to convert some of the sulfides to oxides and to eliminate some of the sulfur. In roasting, most of the required energy is derived from the burning of the sulfur in the concentrate. Roasted concentrate, or calcine, is then charged into the reverberatory furnace. In addition to concentrates and cement copper, the reverberatory furnace charge includes silica rock, lime rock, and ore as fluxing agents, and copper-bearing dust collected from the electrostatic precipitators.

Waste heat from reverberatory furnace flue gas is recovered in recuperators and waste heat boilers. The steam generated is used in the smelter power plant or is consumed in other plant operations. Up to about 50 percent of the fuel energy consumed by the reverberatory furnace is recovered.

Matte, a mixture of copper sulfide and iron sulfide, which contains from 30 to 60 percent copper, is tapped from the reverberatory furnace into ladles for transfer to the converters. Waste slag from the reverberatory furnace contains very little copper and is sent to the slag dump.

The converters are cylindrical furnaces into which compressed air is blown through tuyeres below the surface of the liquid matte. The sulfur and iron in the matte are oxidized, leaving an impure blister copper containing between 98 and 99 percent copper. Most of the heat in the converter operations is provided by the oxidation of the sulfur and iron. A little fuel is needed to keep the converters hot between charges. Electrical energy or process steam is consumed by the blowers which provide air. Slag from the converters is recycled to the reverberatory furnaces. Converter off-gases containing about 4 percent sulfur dioxide are cooled, cleaned of dust, then sent to the sulfuric acid plant.

Blister copper is fire refined at the smelter in the anode furnaces, which may be reverberatory furnaces or cylindrical furnaces similar to the converters. Air is blown through the molten blister copper to complete the oxidation of iron and to oxidize minor impurities such as nickel. After the final oxidation step, the slag is removed and returned to the reverberatory furnace. The oxygen content of the copper is reduced by bubbling reformed natural gas through the melt (poling). A 200-ton heat in the anode furnace may require 1.5 hours for blowing and slag skimming, and 3 more hours for poling. This operation consumes significant quantities of petroleum fuel, natural gas for poling, and electricity for air blowing. Copper anodes are cast directly from the anode furnaces into coated copper molds.

The anodes, which contain 99+ percent copper, are shipped to the refinery. It was estimated that about 750,000 tons per year of anodes and blister copper are shipped 2,000 miles from smelters in Western States to refineries on the East Coast. This amounts to 910 net ton-miles per ton of product, based on 1.65 million net tons of blister and anode production in 1972.

The major operation of the refinery is the electrolytic refining of anode copper to cathode copper, which contains 99.9+ percent copper. The tankhouse is a large consumer of electrical energy for electrolysis and of natural gas or oil for heating the copper solution. The finished cathodes are sold or are melted and cast into refinery shapes such as wirebar, cakes, or continuously cast wirerod. Silver, gold, platinum, and selenium, the principal byproducts of the copper refinery, are recovered from the slimes that drop from the anode into the cell during electrolysis.

Energy consumption figures shown in the flowsheet take into account the energy required for existing pollution control processes and equipment. The primary pollution source in the copper industry is sulfur dioxide generated in roasters, reverberatory furnaces, and smelters. Multihearth roasters, used extensively in the past, and conventional reverberatory furnaces are not easily adapted to the recovery of sulfur or sulfuric acid because the effluent gases contain small amounts of sulfur dioxide. Gases from converters contain enough sulfur dioxide (4 to 6 percent) to permit recovery as sulfuric acid. Some smelters have installed fluidized-bed roasters, in which the effluent gases contain 12 percent or more of sulfur dioxide and for which acid plants can be operated economically. Other companies have discarded the conventional roasters or are using them for the drying of concentrate that is charged into green reverberatory furnaces.

Gases from reverberatory furnaces contain about 2 percent sulfur dioxide. These gases may be passed through electrostatic precipitators before being discharged to the atmosphere through high stacks. The industry is using a monitoring system to measure the sulfur dioxide concentrations at ground level at various distances up to 20 miles from the stack. When the ground-level concentration of sulfur oxides reaches an unacceptable level, the reverberatory furnaces are temporarily shut down. This method of control, referred to as " captaining," has been successful in meeting current air quality regulations, but creates a loss in operating time of about 10 to 15 percent.

Meaningful data on energy needed for controlling sulfur dioxide emissions are not generally available from the copper industry. One company provided estimates for its mining, milling, and smelting operations at various plant locations. The data do not cover individual process operations. The tabulation shown below presents estimates of additional energy that would have to be expended at one smelter (reverberatory, converter, and anode casting operations) if the plant were equipped with controls under the present regulations:

| Year | Emission control energy, percent of total smelter energy |
|---|---|
| 1972 | 1.1 |
| 1973 | 1.4 |
| 1974 | 1.6 |
| 1975 | 13.0 |
| 1976 | 17.0 |

The final estimate of the energy requirement for refined copper was derived almost entirely from data obtained from questionnaires sent to copper producers and from site visits to selected companies. Considerable judgment had to be exercised in the necessary interpretation of this information. The estimated 112 million Btu per net ton of copper is higher than most published estimates; it should be noted that this value includes the energy value for cement copper. One company, which provided what appears to be the most carefully analyzed energy data available to Battelle, estimated its total energy consumption to be 125 million Btu per net ton.

### *Potential Energy Savings*

In the conventional copper smelter, the major energy-consuming operations are the concentrator and the smelter, which require approximately 38 percent and 24 percent of the total energy, respectively. More than half of the energy used in the concentrator is used for fine grinding of the ore prior to flotation. In the smelter, more than half the required energy is used for reverberatory smelting, or about 20 percent of the total energy used for the production of refined copper.

### *Potential Energy Savings in Grinding Operations*

The actual energy consumed in grinding depends very much on the nature of the ore. Principal variables are the ore hardness and the degree of grinding necessary for substantially complete liberation of the valuable components. If the energy consumption is expressed relative to the tonnage of refined copper product, factors such as ore grade and recovery in subsequent processing steps are to be included in the analysis. Therefore, a wide variation in grinding energy per ton of final product is to be expected.

In commercial practice, the grinding process is not completed in a single pass. A portion of the mill product is recirculated continually. This circulating load typically is 200 percent to 300 percent of the feed. The optimum circulating load depends on a number of items such as the grindability of the ore, the cost of electrical energy, and the capital investment in the mill; it must be determined for each case.

Once the optimum circulating load has been determined, every effort should be made to operate a mill under conditions as close to the optimum as possible, which requires that adjustments be made almost continually because of variations in feedload and characteristics and because of wear of the grinding media. Until recently, it was difficult to exercise close control because of lack of suitable instrumentation. Presently, several instruments are on the market that rapidly determine the particle size distributions in the various streams in the mill circuit. These instruments can provide the feedback signals necessary for computerized control of the circulating load at the optimum level. Energy savings typically of the order of 10 to 15 percent of the energy presently used for fine grinding have been published (ref. 8).

There are indications that energy can be saved by the installation of rubber liners in the mills. Although results were not impressive when the liners first became available several years ago, it appears now that, with some minor changes in design, energy savings of the order of 10 percent are readily obtainable (ref. 9).

Another new development that is claimed to reduce energy consumption is the use of fluid energy mills (ref. 10). These devices submit ore particles to tensile forces rather than to the compressive forces used in conventional grinding. Although the tensile strength of rock minerals is known to be much less than the corresponding compressive strength, net overall energy savings evidently have not been demonstrated to potential users. One significant problem area is the wear of components in contact with high-velocity solid particles. Until energy savings are clearly demonstrated, no recommendations can be made. Further developments deserve some attention.

### *Potential Energy Savings in Smelting and Refining Operations (Without Major Process Changes)*

Developments in copper smelting during the last two decades do not reflect a special concern for energy savings. Motivating forces have been the need for effective and least expensive air pollution control systems and for overall cost reductions through process simplification. As a result, two general trends have emerged.

In existing smelters, roasting operations have been reduced or phased out in favor of wet charging of reverberatory furnaces. This has reduced operating and maintenance costs at the expense of higher fuel consumption. In other cases, flash smelting furnaces have been installed, again eliminating roasters, but also replacing the reverberatory furnace with a more efficient unit. Predictably, smelters of this design show the lowest energy consumption in existing copper smelters. The Outokumpu flash smelting process is being installed in New Mexico.

In recent years, much emphasis has been placed on development of a continuous smelting process to conserve energy and to reduce air pollution. Presently, two continuous smelters are being constructed, one in Canada using the Mitsubishi process and one in Utah using the Noranda process. The use of new smelting processes represents major process changes, which are discussed later.

One relatively new development that has not been implemented to a significant degree is the electrorefining of copper at high-current densities using a new cell design that may permit savings in capital investment. The energy required in refining at high-current density is significantly greater than for copper produced conventionally.

Individual companies may achieve significant energy savings by replacement of inefficient haulage equipment by newer items of larger unit size, a situation that is not typical for the industry. Similarly, individual refineries may benefit from the use of titanium cathodes. As a rule, these kinds of improvements have been implemented gradually by most producers.

There appears to be little additional opportunity to conserve energy in conventional processing. One large copper company, after making a detailed study of existing plants, concluded that an energy savings of about 1 percent may be possible without installing a new smelting process or other improvements requiring large capital expenditures (ref. 11).

### *Potential Energy Savings With Major Process Changes*

Based on (1) the energy requirements to produce one net ton of refined copper by conventional means and the total annual energy associated with the U.S. consumption of refined copper; (2) the complexity of the conventional production processes in terms of the number of unit operations and/or chemical reactions associated with refined copper production; and (3) the availability of known alternative energy-saving production processes for producing refined copper, it is considered highly desirable to develop energy-saving replacement technologies (where feasible) for the manufacture of copper.

Energy-saving replacement and/or alternative processes are generally directed toward replacement of the smelting steps. Several operations that offer an opportunity to save energy relative to the conventional smelting procedures include (1) Outokumpu-type flash smelting, (2) continuous smelting, such as the Noranda, the WORCRA, the Q-S, and the Mitsubishi processes, (3) autogenous smelting, and (4) blast furnace smelting.

The type of flash smelting developed by the Outokumpu Smelter in Finland and a variation developed by International Nickel Company in Canada provide a significant fuel savings in comparison with reverberatory smelting. Flotation concentrates, with flux and preheated ore, are injected into a hot chamber where the flash burning of sulfides in suspension furnishes the energy needed for smelting. This reduces the need for auxiliary fuel input and also reduces the volume of the combustion products. Off-gas is produced with the Outokumpu Flash Smelter, which contains 8 to 14 percent sulfur dioxide.

The International Nickel variation uses 95 percent oxygen in place of air. A more concentrated gas is produced, which contains 70 to 80 percent sulfur dioxide. Kellogg has indicated that the Outokumpu-type flash smelter requires only about 40 percent of the energy used in a typical green-charge reverberatory furnace (ref. 12). The Inco-oxygen Flash Smelter is anticipated to provide even greater net energy savings relative to the conventional reverberatory smelter. Besides improved utilization of energy and diminished gas volume, flash smelting practices are considered to yield a higher grade matte than reverberatory smelting. High-copper-content slags are produced in flash smelters and additional energy would be required to reclaim the copper from the high-copper slag.

Combining the conventional reverberatory-converter operation into a single unit should provide an energy savings. A number of these continuous smelting processes have been developed to the pilot-plant stage and a few to the semicommercial stage. Several of the continuous smelting processes are described.

A process developed in Canada by Noranda Mines, Ltd., uses a single, long (about 70 feet), combined smelting-converting unit (refs. 13,14). The unit consists of a horizontal, cylindrical furnace having a central depressed area for copper collection and a round hearth at one end for slag removal. A burner heats the smelting end where concentrates and flux are charged. Air or an air-oxygen mix is introduced through tuyeres along the base of the furnace to oxidize the matte that is formed. Reducing gas conditions are maintained at the opposite end of the furnace for slag reduction and settling. The gas, which leaves near the center of the furnace, is of sufficient sulfur dioxide content for the subsequent production of sulfuric acid. After testing a 100-ton per day pilot operation, Noranda has built an 800-ton per day commercial operation. Kennecott has also announced plans to install a Noranda-type continuous smelter. While detailed energy requirements are not known for the Noranda-type continuous smelter, this process should allow an energy savings over the conventional smelting process.

The WORCRA continuous smelting process has undergone pilot testing over the last few years (refs. 13,15). This process combines smelting, converting, and slag cleaning in one operation within a long stationary furnace. Molten copper is removed from one end of the unit, slag is removed at the other end, and off-gasses are removed as a single stream for subsequent processing. In place of the tuyeres used in the Noranda process, air lances enter from the top of the furnace. An analysis by Kellogg of the operating data for the WORCRA furnace at the Port Kembla pilot plant did not indicate a significant energy savings relative to conventional reverberatory smelting (ref. 12).

Named after the inventors Paul Queneau and Reinhardt Schumann, the Q-S process is also a multistage progressive converter operation that combines continuous smelting and converting in one furnace. Sulfide concentrates are flash-smelted with oxygen, which also is introduced through submerged tuyeres to effect the production of copper. A slag scavenging operation is also part of the process. Pilot-plant investigations of the Q-S process are currently in the planning stage; no estimate of the energy requirements is available (ref. 16).

A process developed by Mitsubishi Metals Corporation of Japan differs from the Noranda and WORCRA continuous processes in that not all of the processing is done in a single unit (refs. 17-19). The concentrates are smelted in one furnace, from which the slag and matte flow continuously through a slag-cleaning furnace into a converting furnace equipped with overhead air lances. The process features countercurrent flow as matte moves from the smelter furnace to the converter, while the converter slag is returned to the smelter.

The Mitsubishi process has been scaled to a 1,500-ton blister copper per month semicommercial plant which started operation in November 1971. Steady-state operation and control of the Mitsubishi process is achieved by on-line, feed-forward computer control of the inputs of air and flux to the converter furnace. Assuming that long-term, steady-state operating conditions can be maintained, the Mitsubishi process may make possible significant reductions in energy consumption relative to the conventional smelting practices.

Autogenous smelting work has been conducted on a laboratory scale by the United States Bureau of Mines (ref. 20). Like the Noranda and WORCRA processes, the Bureau of Mines' autogenous smelting features continuous operation of a single unit to produce copper directly from concentrate. The furnace combines flash smelting with converting by means of an oxygen lance immersed through the slag into the matte. While this process appears to offer the potential for energy saving relative to the conventional smelting processes, no further development of the process appears to be underway.

The Momoda blast furnace developed by Sumitomo Metal Mining Company is currently used by two copper smelters in Japan (ref. 21). Concentrates are charged to the blast furnace with other copper-bearing materials as a stiff plasticized mass containing 10 to 15 percent water. The energy requirement for smelting a ton of charge in a Momoda blast furnace is given as only about 28 percent of the energy required for reverberatory smelting with a wet charge; thus there appears to be a substantial energy savings. While the blast furnace smelting of wet concentrate may provide a lower energy route to copper production than the conventional smelting processes, a detailed analysis of the blast furnace operation is required before the magnitude of the energy savings is known.

Copper may also be produced by hydrometallurgical processes such as Anaconda's Arbiter process, the Sherritt-Gordon process, the Cymet process, and the Duval process (refs. 22-24). While there are few precise data available on the fuel and power requirements, these hydrometallurgical processes do not offer any potential for energy conservation relative to conventional smelting processes. Kellogg has estimated that the hydrometallurgical processes for producing copper require at least twice the energy associated with the conventional pyrometallurgical smelting processes (ref. 12).

## ALUMINUM

Table 7 summarizes production of aluminum ingot from bauxite by the Bayer-Hall process.

### *Estimated Energy Requirements for the Production of Aluminum*

A simplified flowsheet for the primary production of aluminum by the Bayer-Hall route is shown in figure 7, which includes the manufacturing unit operations for carbon anodes and cathodes. Estimated energy consumption is noted for each unit operation. Aluminum production may be subdivided into four major steps: mining,

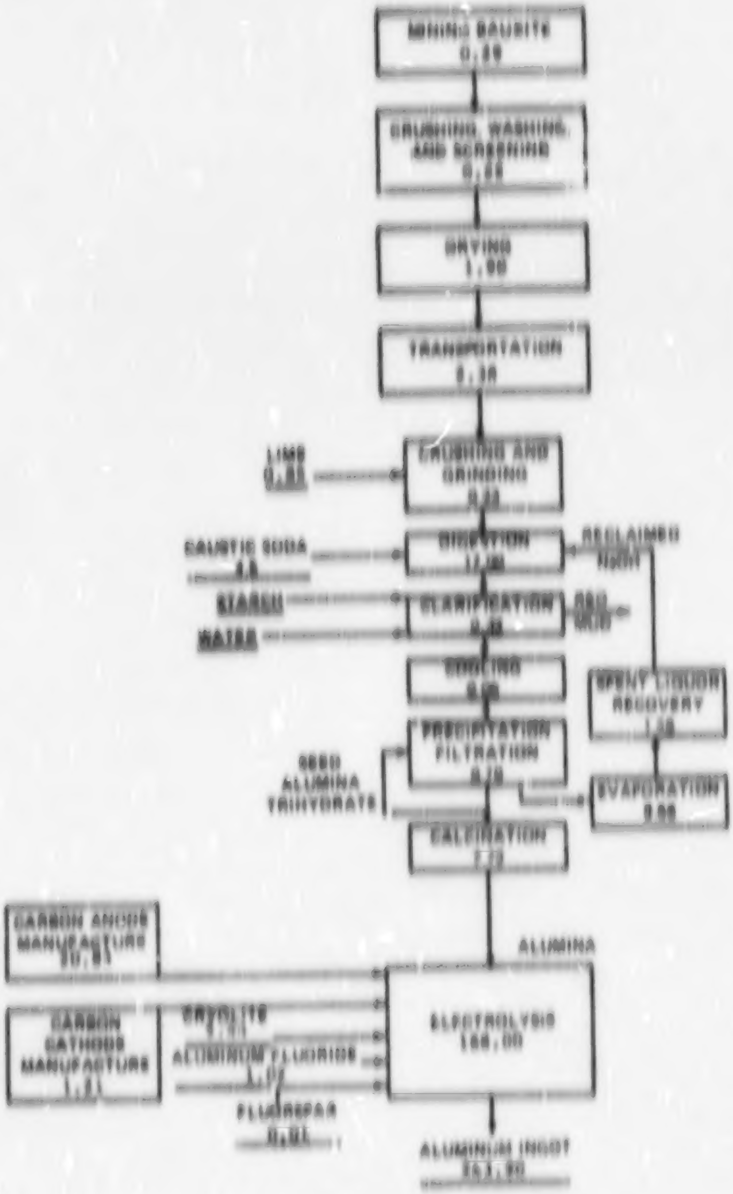

MINING BAUXITE
CRUSHING, WASHING, AND SCREENING
DRYING
TRANSPORTATION
LIME
CRUSHING AND GRINDING
CAUSTIC SODA
DIGESTION
RECLAIMED NaOH
STARCH
CLARIFICATION
RED MUD
WATER
COOLING
SPENT LIQUOR RECOVERY
PRECIPITATION FILTRATION
SEED ALUMINA TRIHYDRATE
EVAPORATION
CALCINATION
ALUMINA
CARBON ANODE MANUFACTURE
CARBON CATHODE MANUFACTURE
CRYOLITE
ALUMINUM FLUORIDE
FLUORSPAR
ELECTROLYSIS
ALUMINUM INGOT

Figure 2. Simplified flowsheet for the production of aluminum from bauxite by the Bayer-Hall route.

### Table 7. Production of aluminum ingot from bauxite by the Bayer Hall process

| | |
|---|---|
| Imports | |
| Bauxite | 85 percent of consumption |
| Ingot | 11 percent of consumption |
| Byproducts | Not important (Gallium) |
| Secondary recovery | 1.23 million net tons |
| Complementary operations | Important (electrode making, 10 percent of energy) |
| U.S. production (primary) | 4.53 million net tons |
| U.S. apparent consumption | 5.77 million net tons |
| Energy required: | |
| Per net ton | 2.44 million Btu |
| Total U.S. | 1408 trillion Btu |

handling, and drying of bauxite at the mine site, transportation of ore to the bauxite refinery, refining of the bauxite into alumina, and smelting the alumina into aluminum.

Most bauxite is surface mined. It is then crushed, ground, and kiln dried to remove excess moisture. Energy requirements for mining have been estimated from the literature on the basis that one net ton of aluminum is received from 4.7 tons of bauxite, the 1974 U.S. industry experience (refs. 25,26,28). The processed ore is transported to the bauxite refinery, which requires an estimated average energy consumption nearly as large as that for the actual mining operations (refs. 27,29). Estimates of the energy required for the transportation of imported bauxite were based on 1973 statistics; imports from each of the exporting countries were proportionately distributed on a ton-mile basis.

Purified alumina is manufactured from bauxite ore in the Bayer process. The ore is digested in caustic soda at elevated temperature and pressure. The insoluble impurities are filtered from the resulting solution of sodium aluminate. The alumina trihydrate, which precipitates from the cooled solution, is then filtered, washed, and calcined in kilns to drive off water of hydration to yield chemically pure alumina.

At the smelter, the alumina is dissolved in the molten cryolite electrolyte in the Hall-type cells. Molten aluminum deposits on the carbon lining at the bottom of the cell, which acts as the cathode. As the aluminum builds up in depth, it is siphoned off. Oxygen in solution combines with the carbon anode at the top of the cell and is released as carbon dioxide. Estimates of the energy requirements for the reduction of alumina to aluminum in the Hall cell are based primarily upon information published by the Bureau of Mines and on industry contacts (refs. 20,26,33). Estimates of the energy requirements for the production of carbon anodes and cathodes are based on contacts with and publications by the aluminum and carbon industries (refs. 29,31,32).

The estimates of energy usage do take into account present knowledge of energy expenditures for pollution control. The most obvious source of emissions to the atmosphere in the aluminum smelter is the gas and fumes from the reduction cells, which contain carbon dioxide, carbon monoxide, sulfur oxides, and fluoride particulates. In plants using Soderberg anodes, the emissions contain tars and oils. Flue gas from the anode bake plant in plants using prebaked anodes contains all of these constituents, since anode stubs are recycled. Dust is formed if solid-pitch-handling systems are used. A final source of pollution is the chlorine-nitrogen-carbon monoxide degassing of molten aluminum in a batch operation carried out in holding-alloying furnaces.

The efficiency of the reduction-cell hooding is a factor which determines the pollution control measures used. Where high-efficiency hooding is possible, air pollution control devices may be applied to the primary pot gas. Lower efficiency hooding (because of cell design) necessitates the treatment of pot room (secondary) air. In the case of primary control of the pot line, either dry or wet gas-cleaning devices can be used. In the treatment of secondary air, only wet gas cleaning devices are practicable. Dry gas cleaning methods involve the use of dry alumina as an adsorbent to remove pollutants from the pot gas. Wet gas cleaning methods include wet electrostatic precipitators and tower or spray scrubbers with or without demisting devices.

Dust formed in the anode paste plant may be controlled with baghouses or with other dry or wet systems. Wet scrubbers are commonly used for the control of emissions from anode bake plants. Wet scrubbers generally are used to clean off-gases from the holding alloying furnaces.

In the Bayer plant, dust from the calciner is controlled with electrostatic precipitators, often with baghouses for final cleanup. Wet scrubbers are used on other dust-producing operations such as conveyor transfer points and lime kilns. In these cases, the waste effluent normally is recycled or is included with the red mud. The dominant waste from a bauxite refinery is red mud; the most common solution to the red mud waste problem is total impoundment.

At present, the total energy expenditure for pollution control for the industry is about 0.81 million Btu per net ton of aluminum, of which 0.59 million Btu is for control of the reduction cell and carbon product exhausts in the smelter, and 0.04 million Btu is for dust control in the Bayer plant calciner. The balance of 0.18 million Btu is for the miscellaneous operations noted above. The industry is in the process of installing additional pollution controls for some of these unit processes. By the end of 1976, installation of Bayer plant calciner controls will have been completed, which will raise this item one-third to 0.06 million Btu per net ton of aluminum. Completion of smelter control installation probably will be finished in the 1978-1980 period. Cell reduction and carbon exhaust control will then account for about 1.77 million Btu per net ton of aluminum; the industrywide total for aluminum production pollution control then will be about 1.90 million Btu per net ton of aluminum.

The thermal equivalent of electrical energy presented here is based on a conversion factor of 10,500 Btu per kWh. (This factor is used uniformly for all commodities included in the master study to assure a common basis.) For aluminum, another perspective should be noted. Almost 40 percent of the electricity consumed by the aluminum industry is generated by hydropower. The Aluminum Association compiled and supplied the following figures on actual electric power sources in U.S. aluminum smelters (1974).

| Source | Percent of supply | Conversion factor Btu per kWh |
|---|---|---|
| Hydropower | 39.9 | 3,413 |
| Purchased thermal power | 41.4 | 10,500 |
| Self-generated thermal power | 18.7 | 12,370 |
| Total | 100.0 | 8,022 |

Using the Aluminum Association factor of 8,022 Btu per kWh would lower the estimated energy required per net ton of primary product from 244 million Btu to 204 million Btu and the total energy required for U.S. consumption from 1,408 trillion to 1,177 trillion Btu.

### *Potential Energy Savings for Alumina Reduction Cells Without Major Process Changes*

There are several areas in the Bayer-Hall process, particularly in the reduction of aluminum in the Hall cell, where modifications in techniques lead to a reduction in energy requirements. Unfortunately, these measures markedly increase the capital cost. Indeed, the magnitude of these additional costs is such as to override the benefits of more efficient operation. Except in cases of plant expansion, such expenditures appear to be more than can be absorbed in the near future by the primary aluminum industry.

Modern reduction cells operate on an electrode potential of 4.5 volts with current flows up to 100,000 amperes. The Faraday (electrochemical) efficiency is 90 percent. However, the power efficiency is only about 45 percent, owing principally to voltage drops caused by high anode and electrolyte resistances.

The high, and apparently inefficient, energy consumption in the Hall cell has caused a continuing effort to reduce power requirements, and it has borne fruit. Whereas the U.S. industry average for power consumption is around 8.6 kWh/lb of aluminum, the most efficient U.S. plants produce aluminum at around 6.5 kWh/lb. The Pechiney plant of Auzat, France, produces 33,000 annual net tons from 140 pots using prebaked anodes operating at 90 KA with a specific power consumption of 5.9 kWh/lb (ref. 34). In this connection, it should be noted that, owing to high energy costs, programs to reduce energy consumption started 10 years earlier in Europe than in the United States.

These reductions in Hall cell energy requirements have been achieved primarily by the following interrelated modifications (refs. 36,37):

1. Installation of larger capacity Hall cells, up to 100,000 amperes, to achieve lower heat losses by reducing the exposed cell surface area per unit of output;
2. Reduction of current density in these larger cells to accommodate the increased anode size and to improve power efficiency;
3. Reduction of the anode and cathode resistances by more efficient lead arrangements which include increasing bus bar cross sections and redesigning the cathode section;
4. Redesign of the bus bar layout to maintain a stable metal/flux interface by minimizing electromagnetically induced turbulence which tends to become increasingly severe at cell sizes above 65,000 amperes capacity.

Purely operational procedures have been adopted to improve efficiency; among these are:

1. Improved control of the interpolar gap at the minimum at which stable operation is maintained;
2. Improved control of temperature as near to the liquids of the flux as possible;
3. Improvements in systems for supplying alumina so as to maintain a maximum amount in solution in the electrolyte;
4. Improvements in the systems for supplying fluoride salts to the electrolyte;
5. Improvements in anode quality;
6. Raising the conductivity of the electrolyte with additions such as lithium and magnesium fluoride, which allow higher current densities without more rapid consumption of the anode.

Making additions to the electrolyte bath raises operating costs. Other recommended measures in the listing above raise capital costs to a marked degree, and the economic justification depends on the costs and availability of power (ref. 38). These modifications will be incorporated into three U.S. plant expansions that are under construction, as well as in two planned expansions and a new hydroelectric plant on which environmental permits are being sought (ref. 39). Together these will raise U.S. capacity 12 percent over the next few years and will reduce the average U.S. Hall cell electrical energy requirement by a few percent. (The new Alcoa aluminum chloride prototype plant under construction is not included in this summarization.)

It should be noted that the new construction will use prebake anode systems rather than Soderberg anode systems, which have much higher voltage losses and thus consume much more energy.

There is still another condition that affects energy usage in Hall cell technology that is based on the cost and availability of energy. In some hydroelectric plants, particularly some in the Pacific Northwest where power costs have averaged 2.0 and 2.5 mils per kWh, output is maximized with some loss in the energy efficiency. In other regions where energy costs are 6 to 7 mils per kWh and up, operation at maximum energy efficiency is preferred, especially in periods of slack demand (ref. 40).

### *Potential Energy Savings for Bayer Processing Without Major Process Changes*

The energy consumed in producing alumina from bauxite is around 17.5 percent of the total energy required to produce aluminum. The process is essentially a large heat exchanger with hot-end digestion of bauxite and cold-end precipitation of alumina. Energy consumed in the process is primarily process heat (90 percent) and electrical energy (10 percent). Over 80 percent of the total energy introduced into the process becomes waste heat. Accordingly, regenerative heating should be employed wherever possible, and heat losses in existing equipment should be kept as low as practicable (ref. 41).

Other changes in Bayer processing which would result in energy savings are conversions which would require considerable capital costs. One of these is a conversion of the process to produce fine, floury alumina rather than the coarse, sandy alumina specified in the United States (refs. 41,42). If European plants, which produce fine alumina, were to switch processes so as to produce the coarse, sandy alumina specified in the United States, productivity would drop 36 percent while the consumption of energy per unit of output would increase by 30 percent (ref. 42).

One area where conversion of existing equipment is economic is the replacement of rotary kilns, used for calcining the alumina, by fluidized-bed calciners. The fluidized-bed calciner uses 30 percent less energy per unit of output than rotary kilns (ref. 43). The industry is in the process of converting.

### *Potential Energy Savings by Process Replacement*

The estimated energy required by the U.S. aluminum industry to produce one net ton of aluminum ingot is 244 million Btu. Based on recent Battelle work, the theoretical minimum energy required to convert bauxite to aluminum ingot is 28.3 million Btu per net ton (ref. 2). The efficiency associated with U.S. aluminum ingot production is slightly less than 30 percent on the basis of 3,413 Btu per kWh, or 14.2 percent if the electrical input is taken at 10,400 Btu per kWh.

The efficiencies of the major energy-consuming Bayer and Hall processes are less than those of many other major unit operations in the steel, copper, and glass industries.[7] Based on the energy requirement and the efficiencies of the major unit operations for aluminum production, it is considered highly desirable to develop energy-saving, replacement technologies (where feasible) for the manufacture of aluminum.

Alternative processes for the production of aluminum have been reviewed and described in a survey by Ing and Zeerleder and in a recent paper by Peacey and Davenport (refs. 44,45). These alternative processes typically fall within three categories: replacements for the Bayer process, replacements for the Hall process which uses Bayer-process aluminum as the primary input material, and processes which replace both the Bayer and Hall processes. Alternative processes of these three types are discussed below.

### *Alternatives to the Bayer Process*

Of the aluminum-bearing materials, bauxite is the richest in aluminum. Untreated bauxite typically contains 55 to 65 percent alumina so that about 4 pounds of bauxite are processed per pound of aluminum produced. Typically, 8 to 9 pounds of clay or kaolin are required per pound of aluminum. The use of a leaner ore than bauxite implies that more ore must be treated and that more energy is required to produce a pure alumina. Because bauxite suitable for the Bayer process is not as available as kaolin or clays, numerous attempts have been made to develop alternative processes. Wet-type replacements to the Bayer process do not appear to offer any major energy savings.

Probably the best known electrothermal process is the Pedersen process, wherein bauxite, coke, limestone, and iron ores are melted in an electric-arc furnace to produce pig iron and a calcium aluminate slag. The slag, typically containing 30 to 50 percent alumina and 5 to 10 percent silica, is treated to produce alumina. The energy assigned the Pedersen process alumina will depend on the credits assigned the pig iron and furnace gases produced in the electric-arc furnace; the calcium aluminate slag is essentially a coproduct. The overall energy requirements for alumina produced via the Pedersen process or other electrothermal methods are generally greater than the Bayer process energy requirement if the electrical energy input to the furnace is taken at 10,400 Btu per kWh.

While the Bayer process appears to be relatively inefficient, alternative processes for producing pure alumina do not offer significant energy-saving potential.

### *Replacement of the Hall Process: The Alcoa Process*

In the Alcoa process, Bayer alumina is chlorinated to produce a gaseous mixture of aluminum chloride, carbon dioxide, and carbon monoxide. The aluminum chloride is separated from the gases by condensation in a fluidized bed of solid aluminum chloride particles. The solid aluminum chloride is introduced continuously into an electrolytic cell containing a fused chloride electrolyte at about 1,290° F (700° C). Liquid aluminum metal is produced at the cathode. Gaseous chlorine, which recycled to the chlorination plant, is formed at the anode.

A simplified flowsheet for the Alcoa smelting process is shown in figure 3 next page. Alcoa has utilized two electrolytic cell designs: a monopolar cell similar to the conventional Hall cell, and a bipolar cell containing four bipolar electrodes. Both cell arrangements are stated to offer reduced power consumption relative to the standard Hall cells, due largely to the greater electrical conductivity of the chloride electrolyte. Peacey and Davenport estimate a 20 percent reduction in electrical energy requirement for the Alcoa smelting process relative to the best Bayer-Hall system (ref. 45). (Alcoa has stated that the Alcoa smelting process could reduce energy requirements by 30 percent relative to the best Hall cell operation.) The more efficient U.S. aluminum producing plants use about 6.5 kWh/lb of aluminum in the Hall cell. A 20 percent reduction (a reduction of 1.3 kWh/lb) would result in a specific energy consumption of 5.2 kWh/lb of aluminum. On this basis, the energy required per net ton of aluminum would be lowered from 244 million Btu per ton to about 195 million Btu per ton. Peacey and Davenport indicate that the Alcoa smelting process would consume about 30 percent less carbon than the best Hall cell operation. They estimate that a 100,000-metric-ton-per-year Alcoa smelting process plant requires 5 percent less fixed capital investment, but 10 percent greater direct operating cost than a comparable size Bayer-Hall system.

### *Alternatives to the Bayer-Hall Processes*

Several processes to produce aluminum have been proposed which would replace both the Bayer and Hall processes. Of the methods considered, two processes may provide an energy savings relative to the traditional aluminum production route. These are (1) electrolysis of aluminum sulfide and (2) the reduction of aluminum trichloride with manganese (the Toth Process).

Electrolysis of aluminum sulfide rather than alumina would provide several advantages: electrolysis at a lower bath temperature (1,560° F rather than 1,740° F in a Hall cell); a greater solubility of the aluminum sulfide in the electrolyte than is possible with alumina in

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[7] The effectiveness values of the Bayer and Hall processes are comparable to those of the major unit operations in the copper and glass industries and generally less than those of the major unit operations in the steel industry. Effectiveness values are essentially equal to efficiencies for aluminum ingot production.

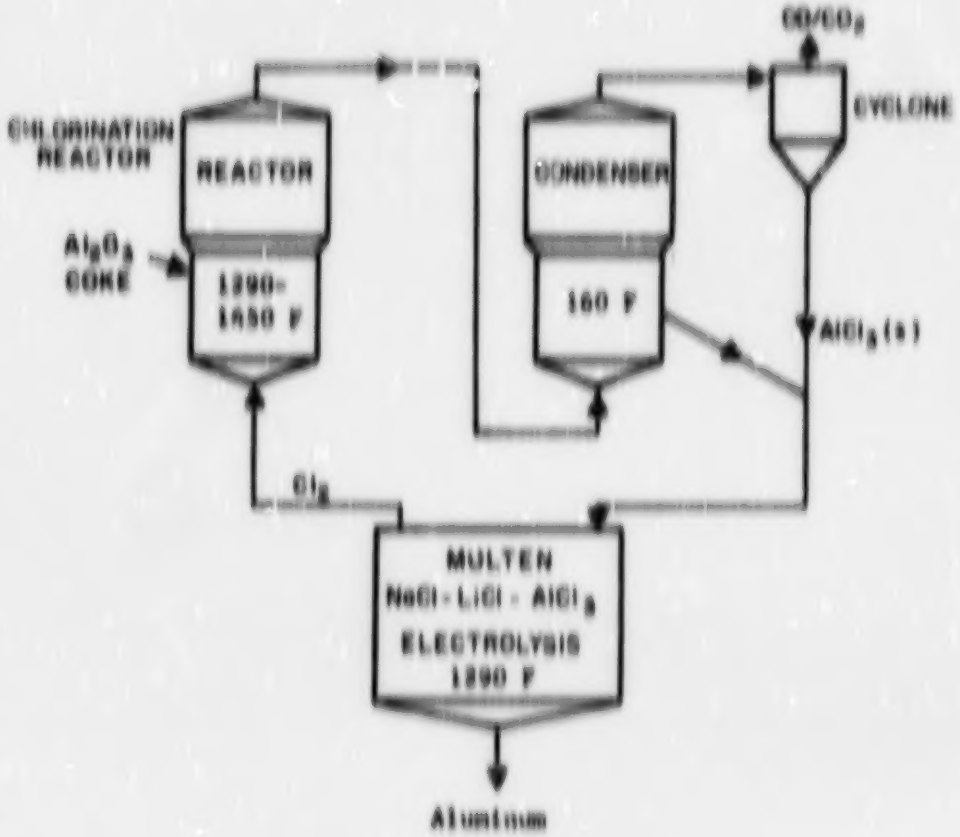

Figure 3. Schematic flowsheet of the Alcoa aluminum chloride process.

cryolite; and a lower consumption of anode material because depolarization of oxygen and its subsequent reaction with the anode would be eliminated. No estimate is available for the potential energy savings with this process. There are, however, some technical problems with the preparation of pure aluminum sulfide and the purity of the resulting aluminum.

The Toth process, which has received much publicity recently, is based on the exchange reaction between manganese metal and aluminum trichloride to give manganese dichloride and aluminum metal. A simplified flowsheet for the proposed Toth process is shown in figure 4. Calcined clay and coke are chlorinated at 1,700° F with a mixture of chlorine and silicon tetrachloride; this technology is well known at present. The volatile chlorides are condensed from the carbon monoxide to yield liquid aluminum chloride. The liquid aluminum chloride would be reduced metallic aluminum and a manganese aluminum chloride salt mixture by reaction with manganese metal. Aluminum chloride is separated from the fused salt by evaporation and subsequent condensation. The remaining solid manganese chloride is oxidized to produce manganese sesquioxide, which is then reduced to manganese metal in a conventional manganese blast furnace.

A major question concerning the purity of the blast-furnace-regenerated manganese and its overall effectiveness in reducing aluminum chloride must be resolved by difficult and expensive experimental development work.

Peacey and Davenport estimate the Toth process would require about 1 kWh/lb of aluminum (ref. 46). The associated operation of a manganese blast furnace with the high carbon requirement per ton of aluminum

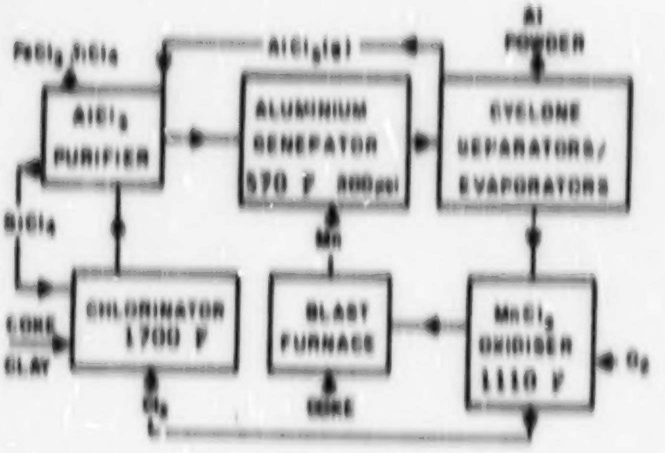

Figure 4. Schematic flowsheet for the proposed Toth process.

may make the energy requirements associated with the Toth Process at least equal to those of the conventional Bayer-Hall processes.

Other processes which are currently being considered to replace the Bayer-Hall processes, such as the Alcan process and the Monochloride process, are not considered energy conserving relative to the best Bayer-Hall technology available. An evaluation and comparison of probable capital and operating costs, electric power requirements, and carbon requirements of the Alcoa, Alcan, Monochloride, and Toth processes with the best available Bayer-Hall technology as reported by Peacey and Davenport are given in table 8, (ref. 45).

Because of the large energy requirement to produce a ton of aluminum and the relatively low efficiency of the Bayer-Hall process, it is highly desirable to develop alternative processes; the Alcoa process appears particularly promising in terms of technical feasibility and possible energy savings. Other processes which may offer future energy savings will require extensive continuing process development and evaluation, or are not currently acceptable to the industry because of reduced purity of the aluminum product or economic considerations. In the reasonably near future, it undoubtedly will be advantageous to the aluminum industry to be able economically to process low-grade domestic ores in order to become less dependent on the supply of foreign bauxite.

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Table 9. Evaluation and comparison of alternative aluminum smelting processes with Bayer-Hall technology (110,000 net tons per year)

| | Processes | | | | |
|---|---|---|---|---|---|
| | Bayer-Hall | Alcoa | Alcan | Monochloride[a] | Toth |
| Fixed capital investment, $ per net ton Al | 1,870 | 1,775 | 1,030 | 1,120 | 1,120 |
| Direct operating costs, $ per net ton Al | 385 | 424 | 385 | 327 | 577 |
| Electrical energy, kWh per lb Al | 6.35 | 5.06 | 11.58 | 6.86 | 0.98 |
| Carbon requirement, lb C per net ton Al | 1,090 | 870 | 2,395 | 1,850 | 10,090 |

[a] Bauxite is taken as starting material.

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# ENERGY CONSERVING INDUSTRIAL CHANGES AND THEIR ENVIRONMENTAL IMPACT

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## Abstract

*Industry uses about 40 percent of the Nation's energy supplies for space heating and process needs. Economic need coupled with technological skill will lead to the development of new energy-conserving processes or practices over the coming years as one means of conserving this costly resource. An EPA funded study has been awarded to Arthur D. Little, Inc., (ADL) to assess the environmental impact of such innovations and to determine whether control technology is or will be available to prevent increased environmental insult from such new processes and practices. A methodology has been developed and used for the selection of the most significant industrial segments. Major processes likely to be implemented by these industries over the coming 15 years as part of the energy conservation strategy have been identified and work is underway to complete the pollution assessments.*

Industry has been estimated to consume approximately 40 percent of the Nation's energy supplies annually, equivalent to about 23 quads ($10^{15}$ Btu), for space heating and cooling, feedstocks, process heat and other miscellaneous internal uses (table 1). The fraction used for each purpose varies grossly from industry to industry and, undoubtedly, from plant to plant within any one industry. Approximately a 10 percent reduction—across the board—could be achieved almost immediately by such means as housekeeping (thermostat control, elimination of heat losses, repair of steam leaks, etc.) and improving insulation and other forms of heat transfer control on process equipment.

Further improvements require a more thorough examination of each industry and its practices and processes. These changes will occur more slowly and probably will be more capital intensive. Nevertheless, another 10 to 20 percent reduction would probably be achievable. The precise level would be determined for each industry by the availability of fuel forms, their cost, and the ability to tradeoff increased cost for continued productivity. It is in this area where more sophisticated changes such as recovery of heat currently being wasted in the form of off-gases, hot water, or steam can occur through the use of heat exchangers, recuperators, and recycle or "cascade" use within a plant. In other cases, energy value is being lost through inefficient use of raw materials, incomplete recovery, or unnecessary disposal.

Table 1. Industrial energy use patterns, 1968 (ref. 1)

| | Percent |
|---|---|
| Direct combustion | 29.0 |
| Process steam | 44.7 |
| Direct electric heating | 1.3 |
| Motors, lights, electrolysis | 25.0 |

A final alternative exists for cutting energy needs still further. This includes relatively complete changes from current manufacturing practices or processes which will come about either because of shortages or feared shortages of a specific fuel form, increased price of petroleum products needed for energy or as feedstock, or simply by the introduction of new, more energy-efficient technology.

Although the latter two classes of innovation, waste heat reuse and new practices and processes, offer significant potential for an improved energy picture for industry, they introduce another unanswered question requiring simultaneous attention: that of pollution control. Drastic changes in industrial manufacturing practices can be expected—at least in some cases—to bring about changes in air, water, or solid waste discharges from those we are currently accustomed to dealing with. For example, if an industry or a single plant changes from natural gas to coal, the pollution generated will be much greater and much more harmful, both at the plant site and, incrementally, at the source of the energy form—the mine. Of necessity, industries will be undergoing changes in their fuel mix over the coming years

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(table 2). Many similar situations can be expected as side effects of industrial efforts to maintain productivity. Although the nature of the pollution which will result from such changes can be estimated at this time, it is important that the environmental impacts of all energy-conserving approaches be considered early in order to (1) encourage those processes which are also environmentally most attractive, (2) discourage or delay introduction of processes for which only inadequate or economically impractical control technology exists, and (3) in the worst case, avoid the introduction of radically new pollutants, the effects of which are as yet unknown. Those instances where energy conservation efforts will also benefit the environment (many of the waste heat reuse schemes can reduce thermal discharges; solid waste incineration for boiler heating can reduce solid waste volume) should be supported and accelerated. In other cases, even where completely new processes replace current schemes, there may be little impact on the pollution generated. These processes will succeed or fail on purely economic reasons. Those energy-conserving changes in industrial practices and manufacturing processes where the pollution from the new approach presents major roadblocks to implementation should require parallel development of adequate control technology at acceptable cost. The final type of changes, those where the pollution simply is not sufficiently well identified to allow a sound decision to be made, will require additional research to establish both acceptable and safe pollutant discharge levels and appropriate control technology.

In any case, the environmental impact or the environmental consequences of any altered technology should play an important role, both for the government and for industry, in assessing the desirability of new energy-conserving technology. It would be both socially and economically unwise to allow an energy-conserving process to be developed and implemented only for it to face severe and/or costly environmental restrictions or to consume the very energy saved by the process change in add-on pollution control.

In wrestling with this subject some months ago, EPA decided that a companion program was needed for the work underway by FEA and that anticipated by ERDA in the industrial energy conservation area. The intent of this program would be first to independently identify major changes in industrial processes or practices which would be likely to come about over the next generation or so in industry's effort to reduce its energy intensity.[1] After establishing that the selected processes would conserve energy or energy forms in short supply, as complete as possible an assessment of the environmental impacts—whether positive or negative—would be undertaken to establish whether the process changes could be expected to be free of more serious environmental consequences than the current practices. In order to accelerate those programs with the greatest energy and environmental benefits, it was recognized that FEA, ERDA, DOC, and EPA would have to work

Table 2. Selected industrial energy sources, 1971, by percent (ref. 2)

| | Steel | Paper | Cement (ref. 3) | Glass |
|---|---|---|---|---|
| Coal | 64.5 | 13.1 | 32.0 | 0.0 |
| Fuel oils | 8.4 | 18.4 | 12.0 | 5.6 |
| Natural gas | 20.6 | 23.8 | 37.0 | 77.2 |
| Purchased electricity | 4.2 | 11.6 | - | 17.1 |
| Other | 2.6 | 33.1[a] | 19.0 | 0.0 |

[a] Residues used as in-plant energy sources.

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[1] Energy required per unit of product.

together and, where necessary, support those tradeoffs in both energy conservation and environmental protection and regulation which seemed to yield the greatest national benefit.

In one complex sentence which became the title, the entire intent of the project as it evolved can be summed up: "Assess the environmental impacts of anticipated energy conserving manufacturing process options and the adequacy of available control technology." Considerable soul searching was devoted to the question of whether this project was best handled by separate contracts for each industry or a single contract covering all (and "all" referred to an arbitrary dozen) industries. It was concluded that for management purposes and consistency in approach a single contract was preferable. Naturally, the contractor could use as many subcontractors or consultants as he wished. The project was initiated in June 1975 with award to Arthur D. Little, Inc., of Cambridge, Massachusetts, as Contract 68-03-2198 (ref. 2).

The initial task of the project, development of a methodology for selecting the 12 "best" industry segments based on energy use, potential changes expected, the scale of the environmental impact of the industry, and the anticipated environmental effects of the innovations expected to be introduced by the industry, has now been completed. After much additional soul searching, discussion with the EPA project officer and consideration of some of the auxiliary goals of the project for ERDA, FEA, and DOC, it was agreed by all parties that while sufficient quantitative information concerning the energy uses of most industries existed, the potential for change and the environmental impact of those anticipated changes could only be evaluated in advance on a more subjective basis, taking advantage of the combined knowledge of EPA and ADL staff members. (Input from industrial representatives was also to be factored into the project as time and OMB clearance permitted.) Combining these factors of energy intensity (see table 3 for some examples), potential for change, and environmental impact, a ranking of industrial segments was derived by ADL, which, after discussion with EPA and FEA, was accepted as a reasonable basis for the indepth assessment studies. There were few surprises on this list (tables 4, 5) although anyone else could certainly make a case for some changes, depending on definition of terms or the level of aggregation/disaggregation used within an industrial segment. Admittedly, a degree of second guessing also contributed to the final selections through our suggestions of how Standard Industrial Classification (code) (SIC) segments might best be aggregated, i.e., 2-, 3-, or 4-digit SIC codes. An attempt was made not only to select the most energy-intensive segments but to touch upon industries of different technological or business character so that the results of the study would establish a broad pattern that could be applied to future analysis of other segments.

Certain other ground rules also were imposed by

Table 3. Estimated energy intensivity — selected industrial segments, 1971, (ref. 2)

| Industry - (SIC) | Total energy (quads) | Energy/Unit ($10^6$Btu/ton) | Energy per value added ($10^6$Btu/$) | (¢/$) |
|---|---|---|---|---|
| Steel (3312) | 1.68 | 19.0 | 0.16 | 11.2 |
| Petroleum refining (2911) | 1.66 | 0.4 | 0.36 | 12.8 |
| Primary aluminum (3334) | 0.59 | 173.0 | 0.72 | 26.6 |
| Alkalies/chlorine (2812) | 0.24 | - | 0.52 | 24.5 |
| Cement (324) | 0.52 | 6-8.0 | 0.45 | 21.0 |
| Glass containers (3221) | 0.17 | 18.2 | 0.12 | 7.0 |

Table 4. Industrial energy consumption, 1968, (ref. 4)

| Industry segment | SIC | Energy consumed<br>quads | <br>Percent of industrial |
|---|---|---|---|
| Primary metals | 33 | 5.3 | 21.2 |
| Chemicals and allied products | 28 | 4.9 | 19.6 |
| Petroleum refining and related industries | 29 | 2.8 | 11.2 |
| Food and kindred products | 20 | 1.3 | 5.2 |
| Paper and allied products | 26 | 1.3 | 5.2 |
| Stone, clay, glass, concrete | 32 | 1.2 | 4.8 |
| All others | | 8.0 | 32.0 |
| Industry total | | 25.0 | |

EPA to avoid overlap with other programs of EPA or other agencies. For example, as a general rule, fuel switching was excluded where it was used to raise steam or generate electricity; where it affected the process, as in direct firing for cement or glass manufacturing, it was accepted as a possible approach to be considered. In general, the industrial power plant was totally excluded from the study so that attention could be devoted to changes in the battery limits of the manufacturing operations. Similarly, although we recognized that many opportunities exist for "over the fence" conservation of energy, these were excluded as being unique and site specific. Even internal waste heat utilization was excluded, where it contributed no apparent impact on the process. Where direct contact, such as in preheating of feed materials as has been suggested in the glass industry, could be anticipated to change the pollutant discharges, such modifications became acceptable candidates.

A number of peripheral questions were soon raised. Although change in feedstock was included as one "process change" to consider, it was decided not to carry out full assessments of the effect of increased use of scrap materials such as iron, aluminum, glass, and paper even though it was recognized that energy consumption might be reduced by as much as 90 percent relative to that required for virgin materials. This decision was based on a judgment that the plant limits for both energy and environmental factors were reasonably well known and that the impact of scrap use was more socio-economical or institutional in character rather than technical and revolved about collection, transportation, acceptability of different products, as well as regulatory restrictions. It was agreed, however, that situations where such socioeconomical, institutional, or regulatory influences controlled the likelihood of implementation rather than technological barriers, these would be identified and discussed in qualitative terms but left for possible future study under a different set of project guidelines.

As shown in table 5, at least the first five industry segments would seem to deserve attention if only because of their gross energy use and their overall importance to society and its energy needs. Even a small change in the practices of these industries could, if widely implemented, have a significant impact on national energy use, but could concurrently have a marked environmental impact if precautions were not taken. Inclusion of these industries should come as no surprise. The remainder of the industries selected presented something more of a problem. Here it was necessary to consider

Table 5. Industrial energy use rankings, 1971 (ref. 2)

| Industry (SIC) | Energy use |  |
|---|---|---|
|  | Percent of total industrial[b] | $10^{15}$ Btu/yr |
| *Blast furnaces and steel mills (3312) | 7.3 | 1.68 |
| *Petroleum refining (2911) | 7.3 | 1.68 |
| *Paper and allied products (26) | 6.9 | 1.59 |
| Food and kindred products (20) | 5.5 | 1.27 |
| Olefins (2869) | 4.2 | 0.98[a] |
| *Ammonia (287) | 2.7 | 0.63[a] |
| *Aluminum, primary (3334) | 2.6 | 0.59 |
| *Textile mill products (22) | 2.3 | 0.54 |
| *Cement, hydraulic (324) | 2.2 | 0.52 |
| *Glass ( )[c] | 1.3 | 0.31 |
| *Alkali and chlorine (2812) | 1.0 | 0.24 |
| Motor vehicle parts (3714) | 0.8 | 0.19 |
| Electrometallurgical processes (3313) | 0.6 | 0.14 |
| Gray iron foundries (3321) | 0.6 | 0.13 |
| *Phosphorus and phosphoric acid (2819) | 0.4 | 0.10[a] |
| Lime (3274) | 0.4 | 0.10 |
| *Primary copper (3331) | 0.3 | 0.08 |
| *Fertilizers (2871) | 0.3 | 0.08 |

[a] ADL estimates.

[b] Based on a 23.1-quad industrial usage; includes losses in conversion of fossil fuel to electric power.

[c] 3211, 3221, 3229, 3296.

*Included in ADL study.

more subjectively the energy and environmental impact potential of specific changes within each industry and possible major shifts in the nature, economics, or even the siting of an industry. Admittedly, as noted earlier, other choices might have been equally appropriate.

The contractor has now gone on to identify the specific processes or practices which seemed appropriate within each industrial segment. Here again, considerable soul searching and bending of the original ground rules took place in an effort to generate a product useful to other agencies as well as to EPA and one which would touch on different conceptual approaches to energy conservation and/or environmental protection.

Tables 6-9 present some examples of the technology innovations identified by ADL as being *considered* within the different industrial segments. Final selections will be made by ADL after discussion with EPA and industrial representatives. In this way we hope to insure that the selected processes are reasonable and a realistic prediction of what will happen—assuming no other major perturbations are placed on the system.

ADL work is now proceeding in three directions. Staff members are collecting the available energy and material balance information for the selected processes. They are generating as much information as possible concerning the potential pollutants and their levels—including new or different pollutants. Finally, they are identifying peripheral factors that should be considered, such as the importance of transportation, shifts in industry siting, trends from localized pollution (in-plant power generation) to centralized pollution (central power plants), etc. Another problem recognized is that as a process becomes more "blue-sky," adequate assessment of energy, economics, environmental impact, and the probability of succeeding become less definitive. Since full studies for such processes would be a rather academic exercise and it is unlikely that such completely new processes would achieve widespread use in the next 15 years or so, ADL has chosen to concentrate on processes which are more likely to play a commercial role over the next 15 years.

The program has been formulated so that the results for different industrial segments will be completed at intervals over the next 3 or 4 months (December-March). Shortly thereafter (May 1978), ADL will issue a summary report in which certain general, broadly applicable new technology will be explored and general conclusions will be presented. Of particular value to EPA, areas will be highlighted where additional R&D is needed to more soundly identify and quantify the pollution of new processes or to accelerate the development of generic pollution control technology to support the most beneficial, or at least the minimally injurious processes from both the energy and the environmental points of view. As

Table 6. Anticipated change: steel industry — blast furnaces, (SIC 3312) (ref. 5)

Annual fuel consumption 1.7 quads (1968)

| Options | Impact<br>Energy | Environment |
|---|---|---|
| Coke dry quenching | Est. $10^{14}$ Btu recoverable as high-pressure steam | Reduced quench water discharge |
|  | Reduced coke use (2-3 percent) | Reduced coke dust |
| BOF Off-gas collection | Est. $10^{13}$ Btu recoverable | Reduced thermal discharge |
|  |  | Reduced particulates |
|  |  | Reduced fossil fuel burning |

Table 7. Anticipated change: container glass industry (SIC 3312)

Annual fuel consumption 0.155 quads (1971), 75 percent as natural gas

| Options | Impact |  |
|---|---|---|
|  | Energy | Environment |
| Coal direct fired | Conserve natural gas | Increased $SO_x$, $NO_x$ particulates |
| Batch preheating | 20-35 percent total savings potential; equivalent to 0.03-0.05 quads | Reduced $NO_x$ (lower temperature), $SO_x$, particulates (scrubbing) |

Table 8. Anticipated change: textile mill products (SIC 22)

Annual fuel consumption 0.5 quads (1971) 30 percent electric, 70 percent fossil

| Option | Energy | Environment |
|---|---|---|
| Al from $AlCl_3$ (Alcoa smelting) | ~30 percent reduction in electrical power needs | Undefined<br>Closed system should reduce pollution |

Table 9. Anticipated change: aluminum (and alumina) (SIC 3334) (refs. 4,6)

Annual fuel consumption 0.59 quads (1971)
Est. 90 percent electric, 10 percent fossil

| Option | Impact |  |
|---|---|---|
|  | Energy | Environment |
| Solvent finishing and [illegible] dyeing | Up to 50 percent reduction in steam requirements<br>Reduced natural gas needs for drying | Reduced wastewater<br>Reduced power plant discharges<br>Increased solvent emissions |

noted earlier, it can be expected that certain process options will be identified where energy conservation and pollution abatement efforts are joined to give an overall advantageous package. Others will occur where the known hazards of the new processes, or the cost or energy requirements of appropriate control technology will be so great as to overwhelm the energy savings achieved in the process. Still others will have relatively unchanged environmental impact. And finally, there will be certain processes where insufficient information exists to definitively place the process in one of the three foregoing classes but where energy saving is an incentive to develop cost- and energy-effective pollution control technology.

Yet another conceptual "grouping" exists, one which could fit into any of the classes just noted. This includes processes which offer such large energy savings that tradeoffs with the level of environmental protection must be considered; thus, modifications of applicable environmental regulation may have to be considered in order NOT to hinder the development and widespread implementation of such processes. ADL will attempt to classify these process options, identify the additional knowledge or technology needed, and point out where, in their opinion, such regulatory tradeoffs are possible and the benefits they offer. It will, however, remain the responsibility of the EPA, working together with other interested Federal agencies (FEA, ERDA, DOC, etc.) to make the final determinations of how best to meet our Nation's energy demands safely.

In closing I would like first to apologize for not having more quantitative data at this time. Secondly, as the EPA project officer for this project, my thanks to Mr. Haley and Dr. Kusik of ADL and the staff now devoted to this project, as well as to the scientists of EPA and other Federal agencies who are so willingly participating in the development and review of this program.

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